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(51) Int Cl^7: **E21B** 7/20 33/14 43/10

(21) Application No: **0310101.1**

(22) Date of Filing: **06.03.2000**

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0005399.1 under Section 15(4) of the Patents Act 1977

(43) Date A Publication: **27.08.2003**

(52) UK CL (Edition V):
E1F FCM FJT FLA

(56) Documents Cited:
WO 2000/077431 A

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As for published application 2385621 A *viz:*
UK CL (Edition V) **E1F** FCM
INT CL^7 **E21B**
Other: **Online: WPI, EPODOC, JAPIO**
updated as appropriate

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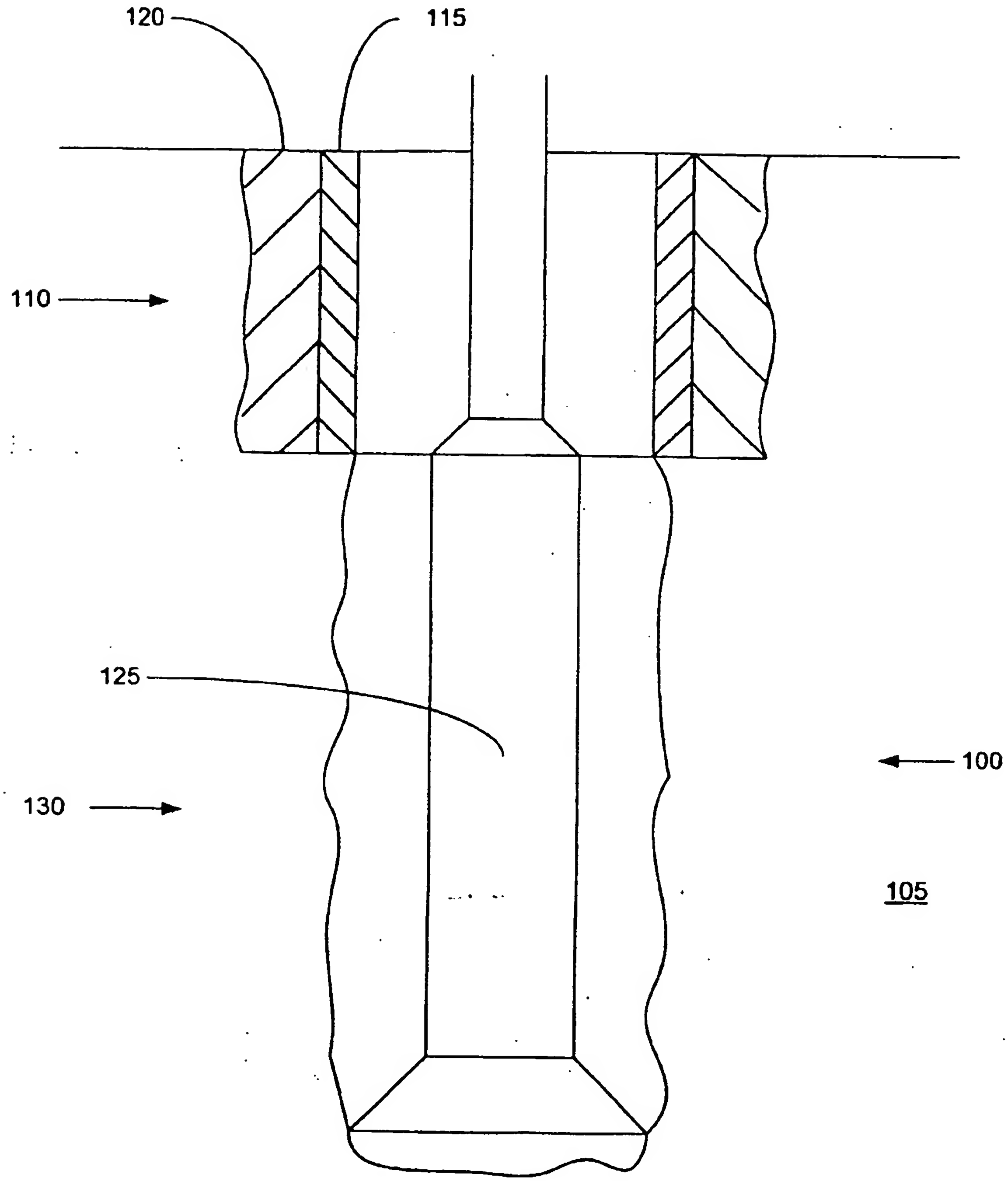

FIGURE 1

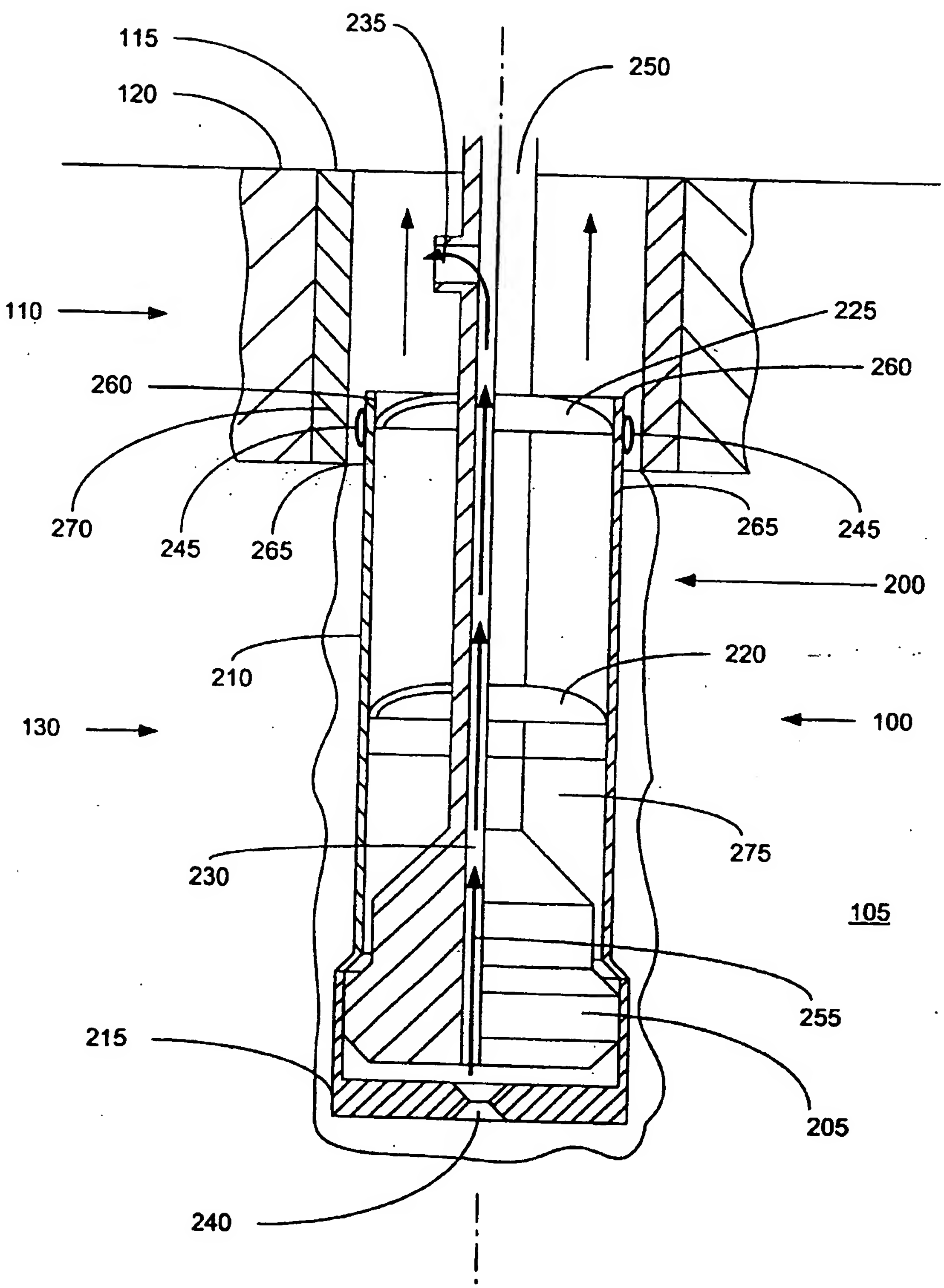
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FIGURE 2

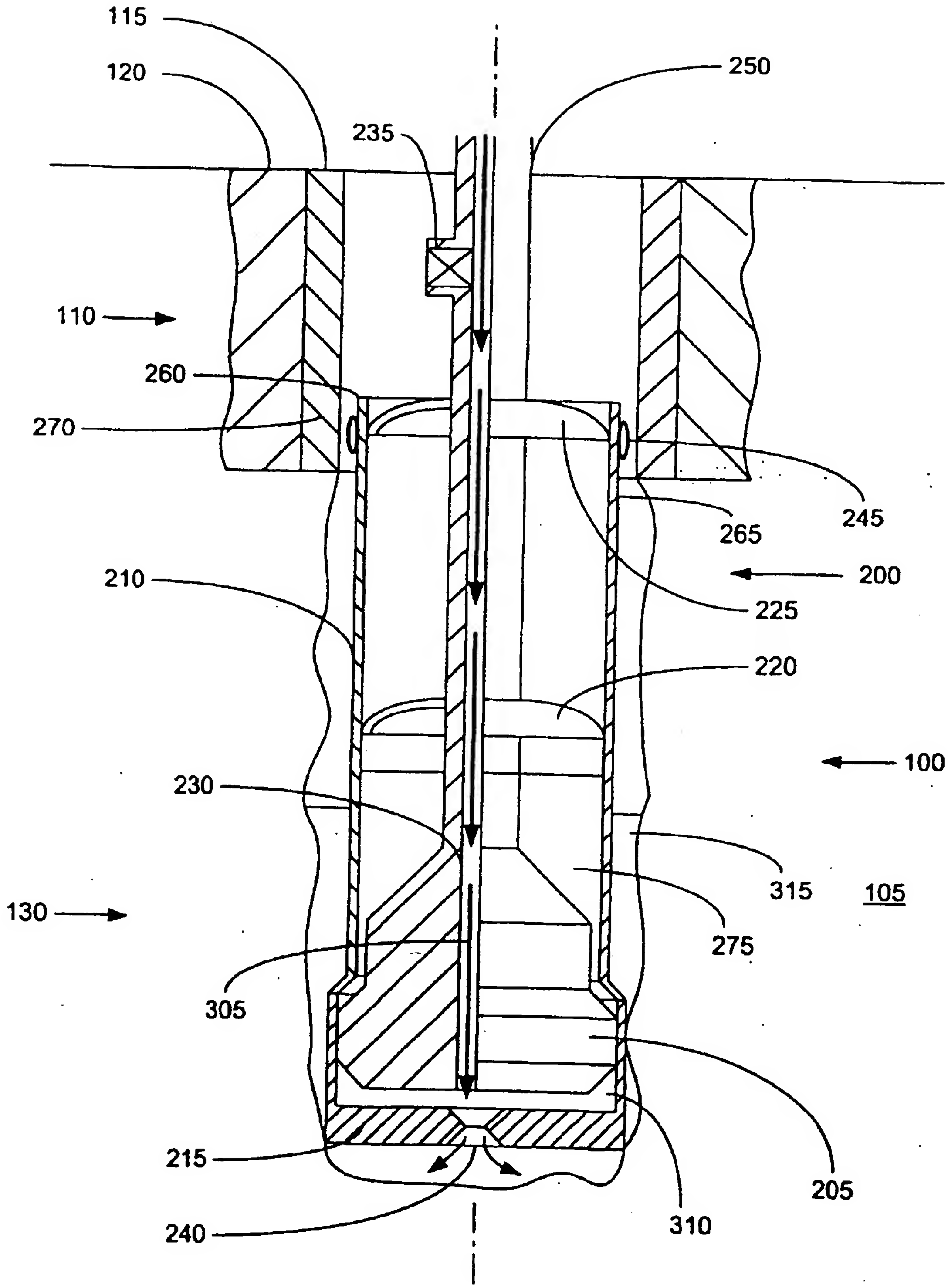
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FIGURE 3

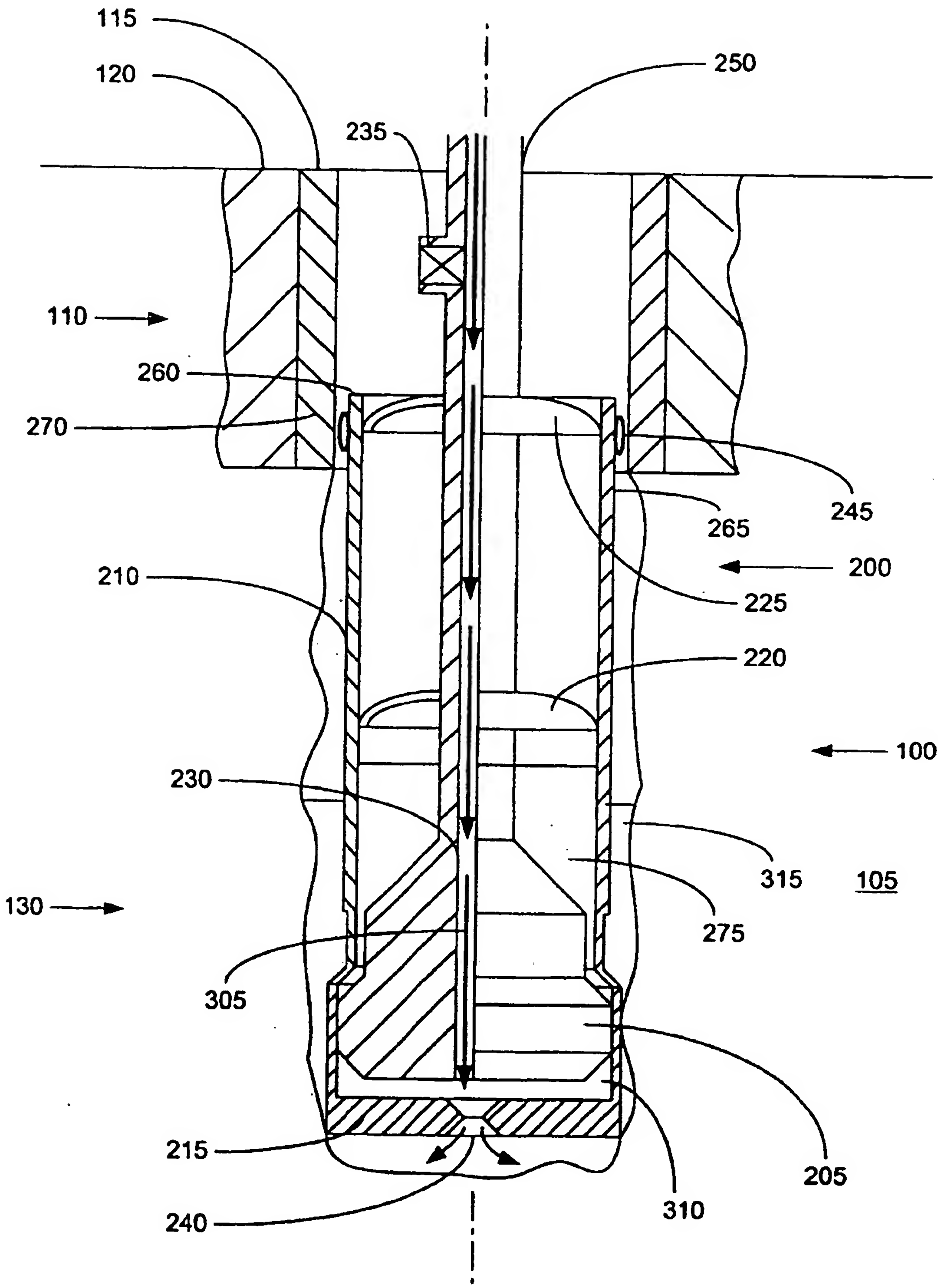
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FIGURE 3a

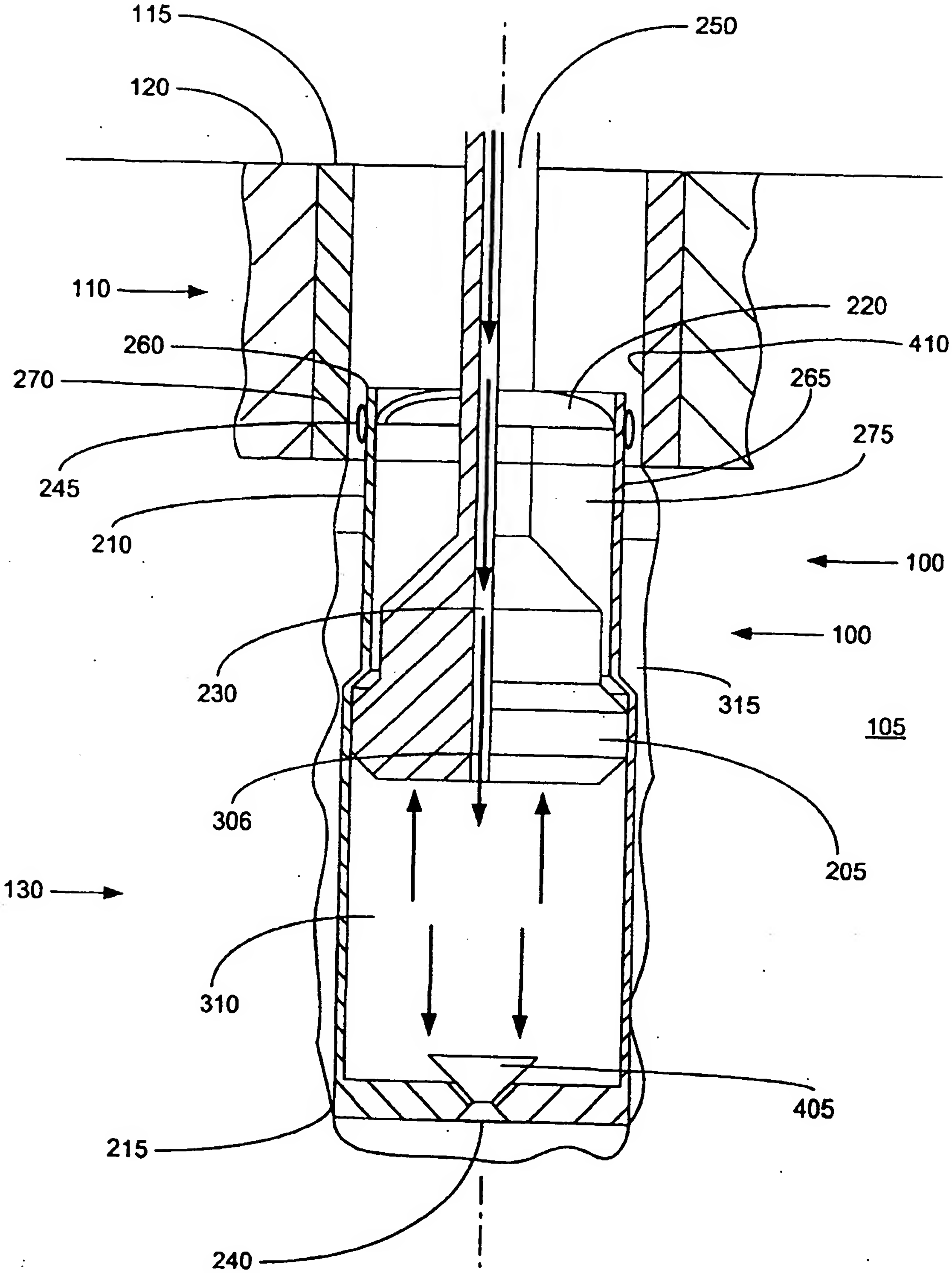
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FIGURE 4

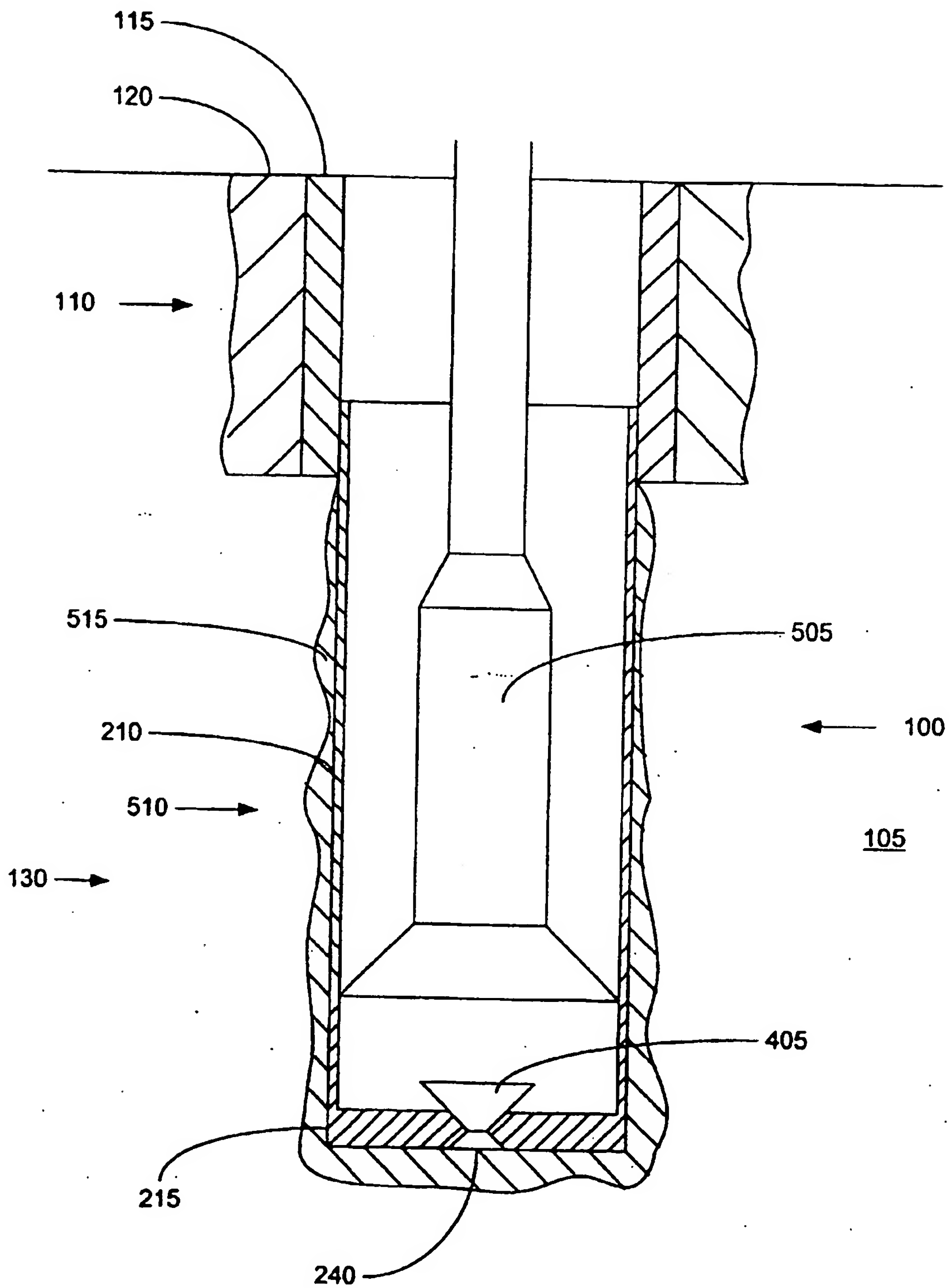


FIGURE 5

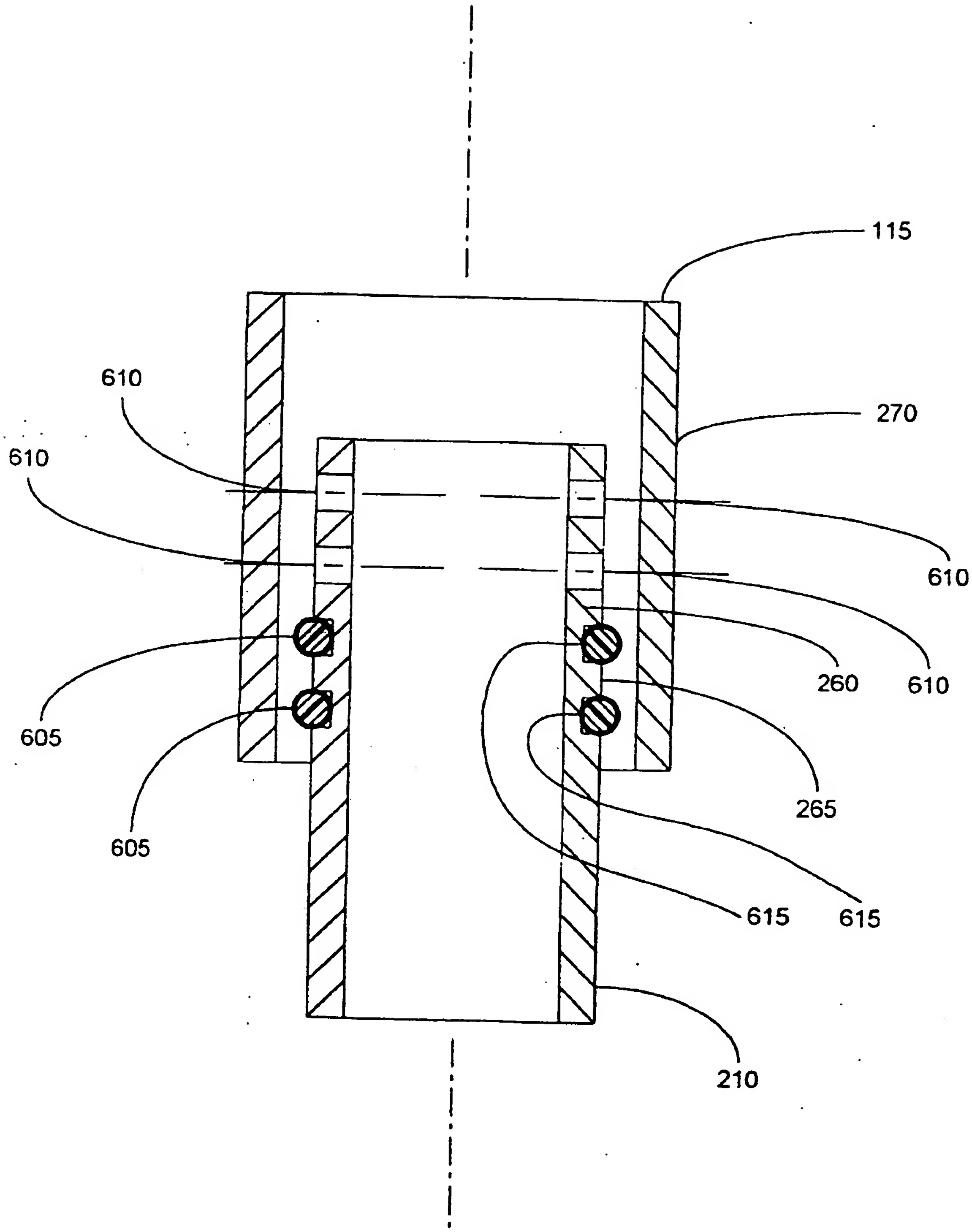
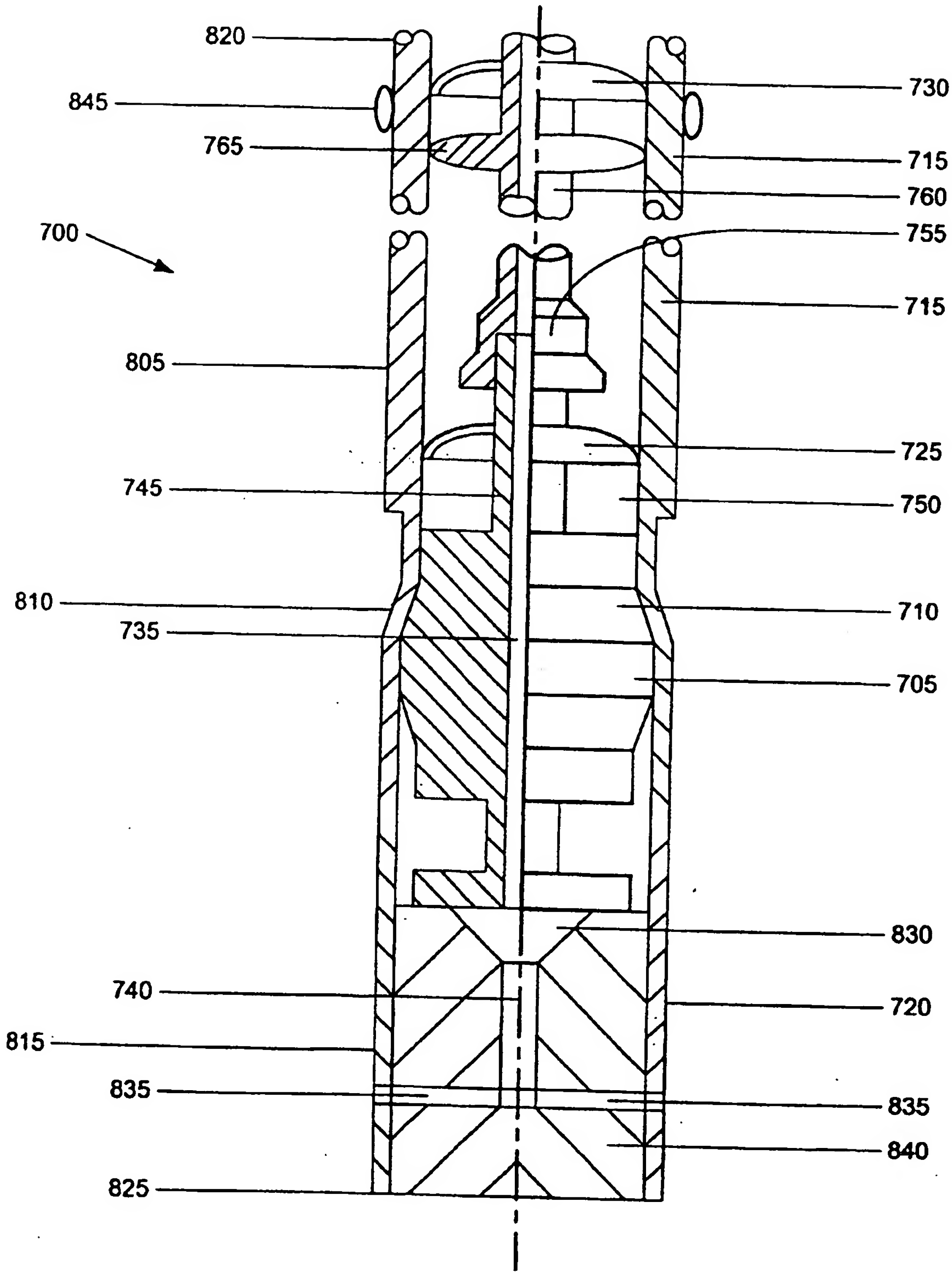


FIGURE 6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705
830
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835
840

FIGURE 7

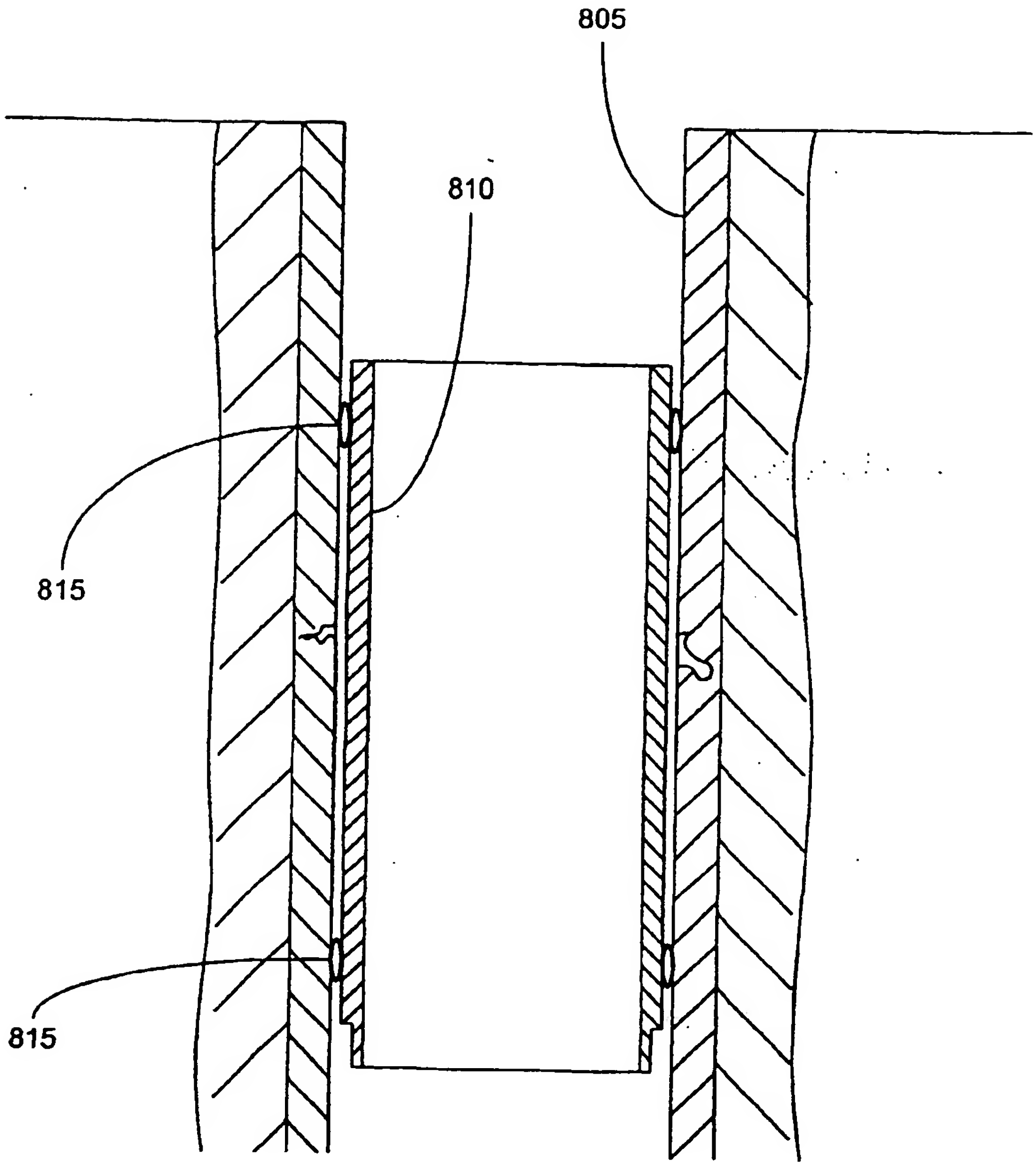
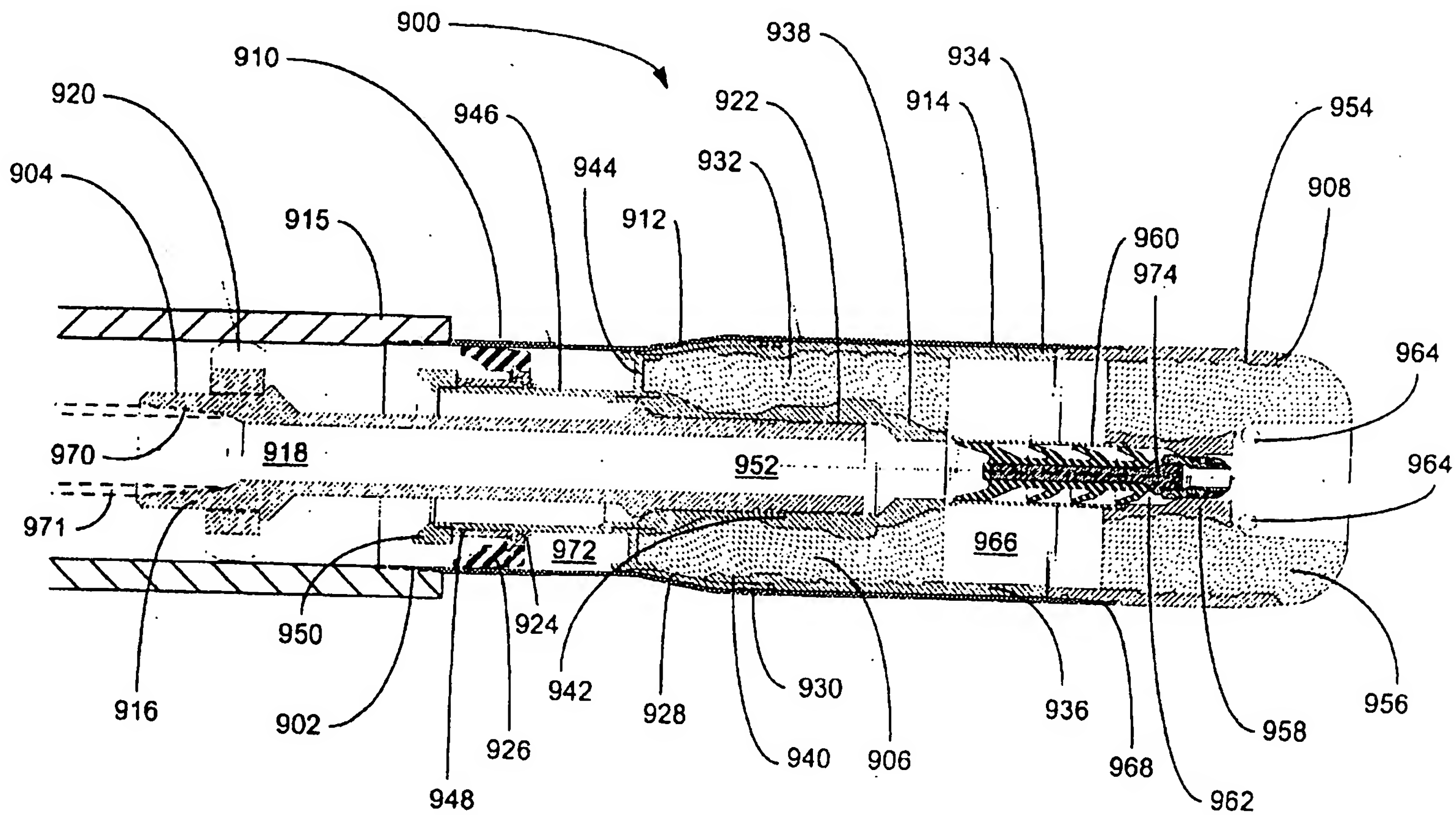


FIGURE 8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970
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940
906
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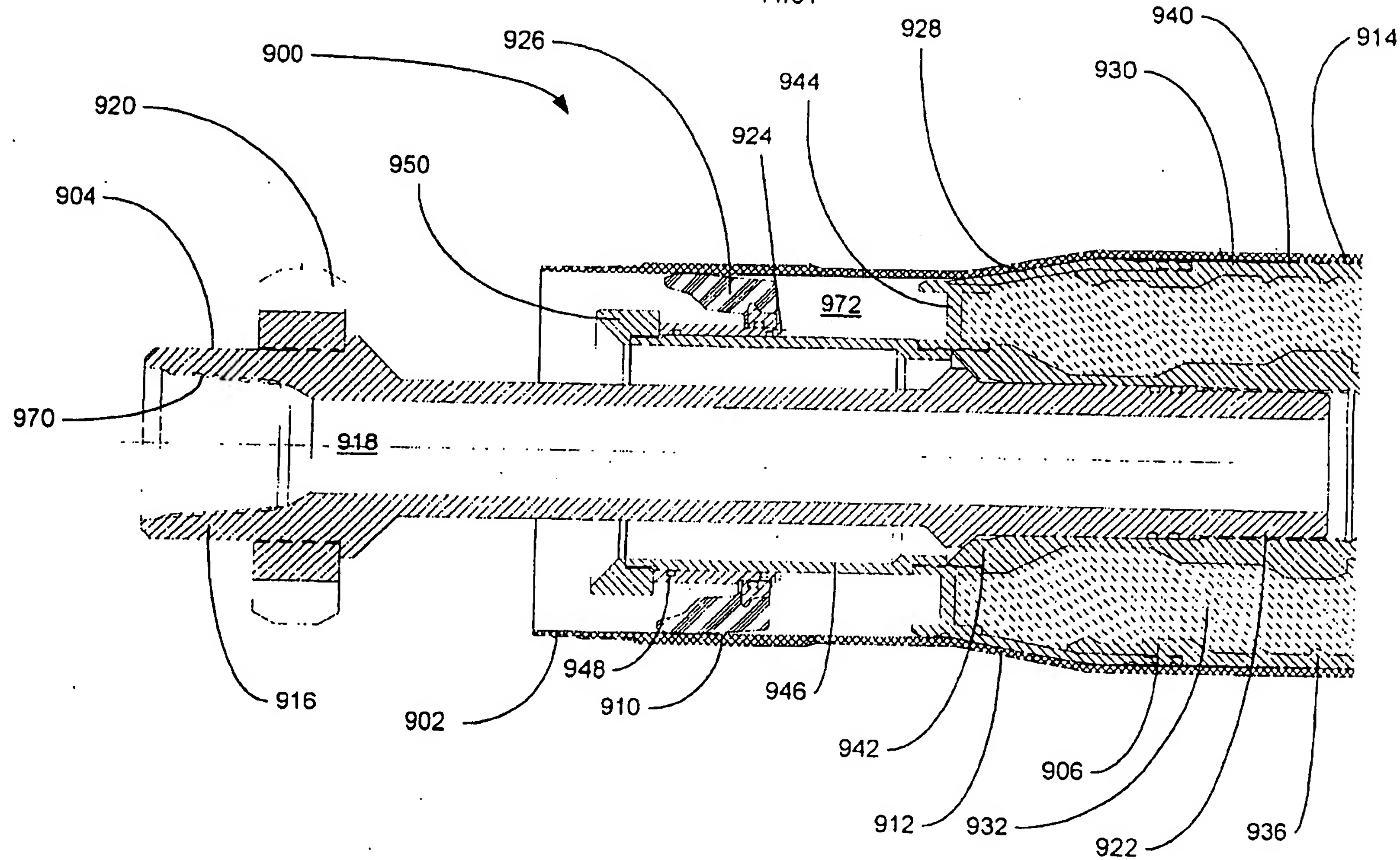
958
956

FIGURE 9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906
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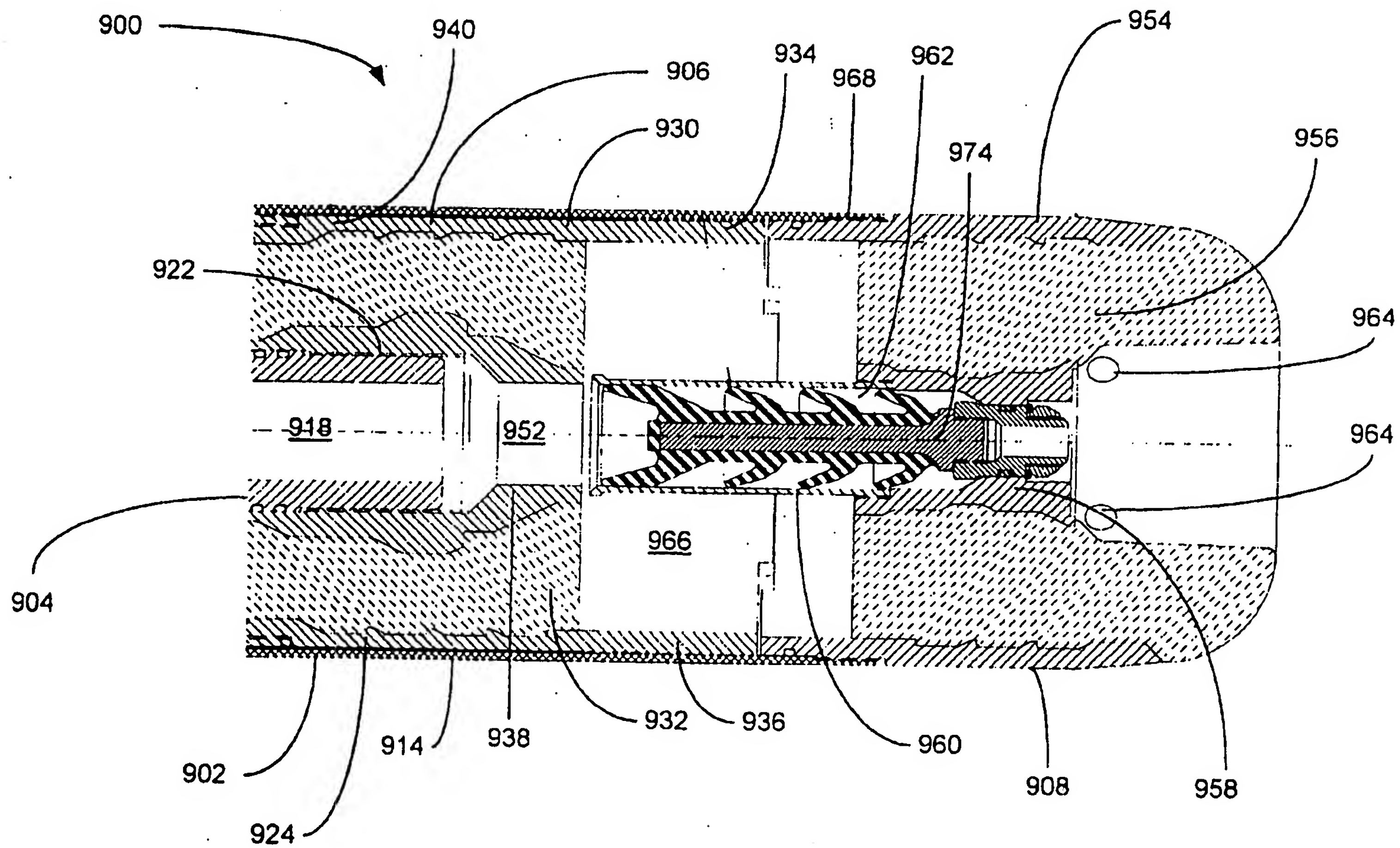
936

FIGURE 9a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960
908
958

FIGURE 9b

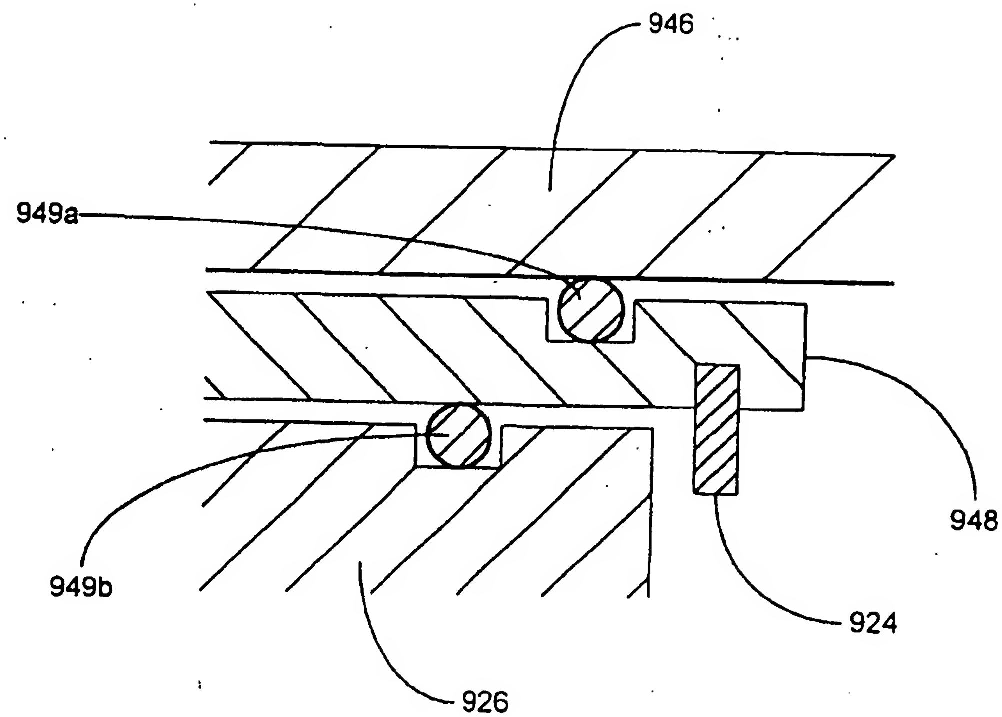


FIGURE 9C

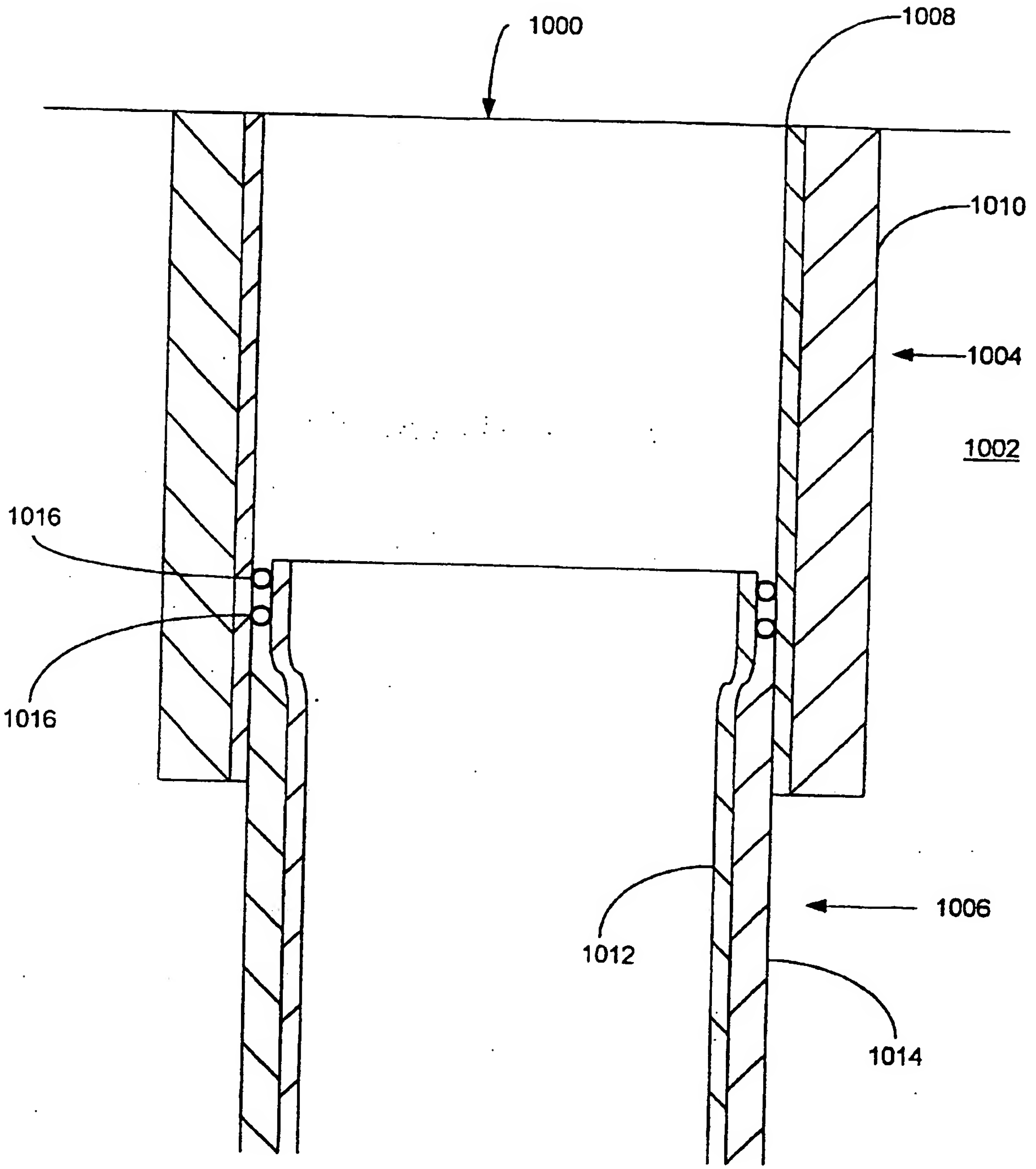
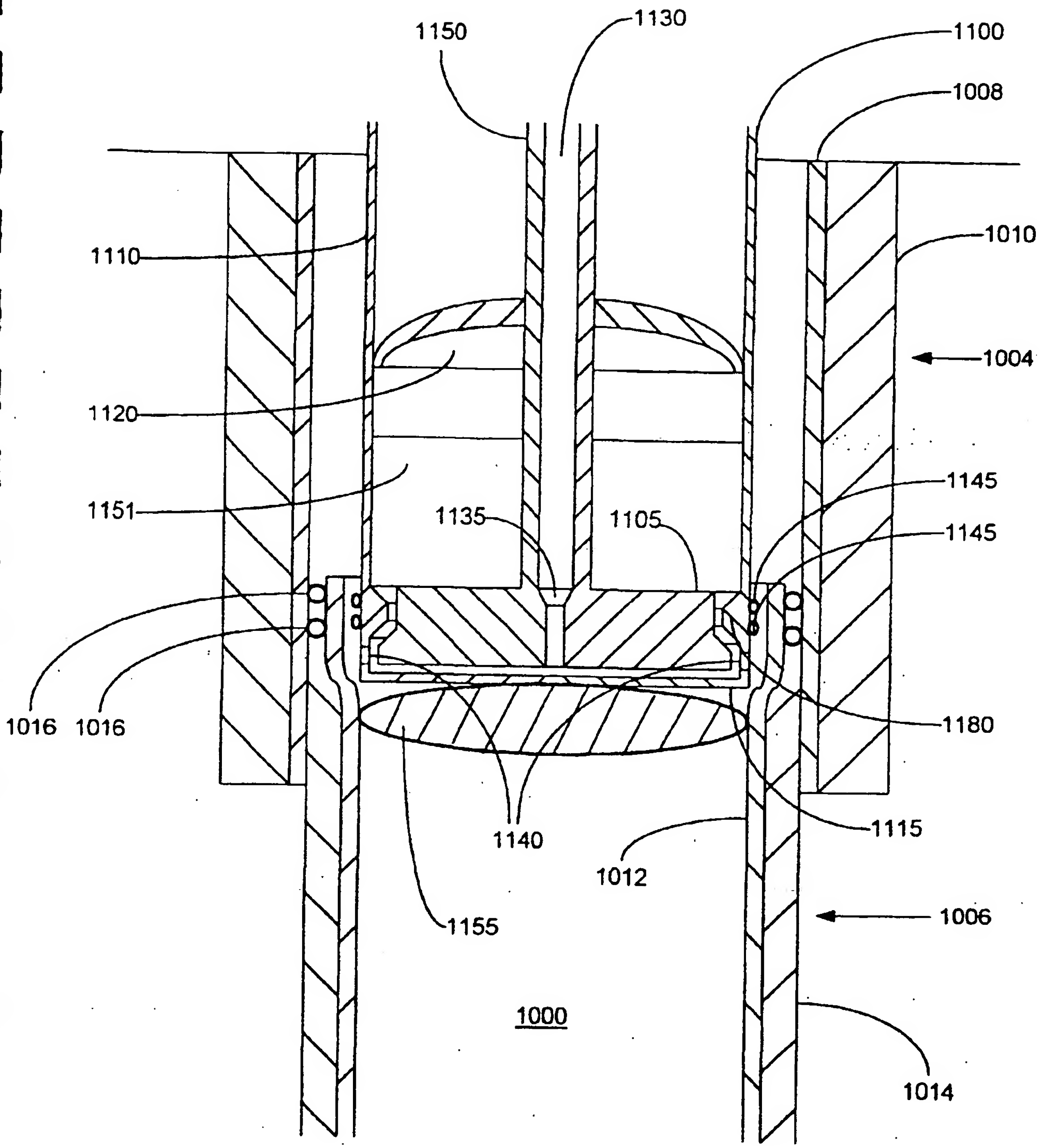


FIGURE 10a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1010
1004
1120
1151
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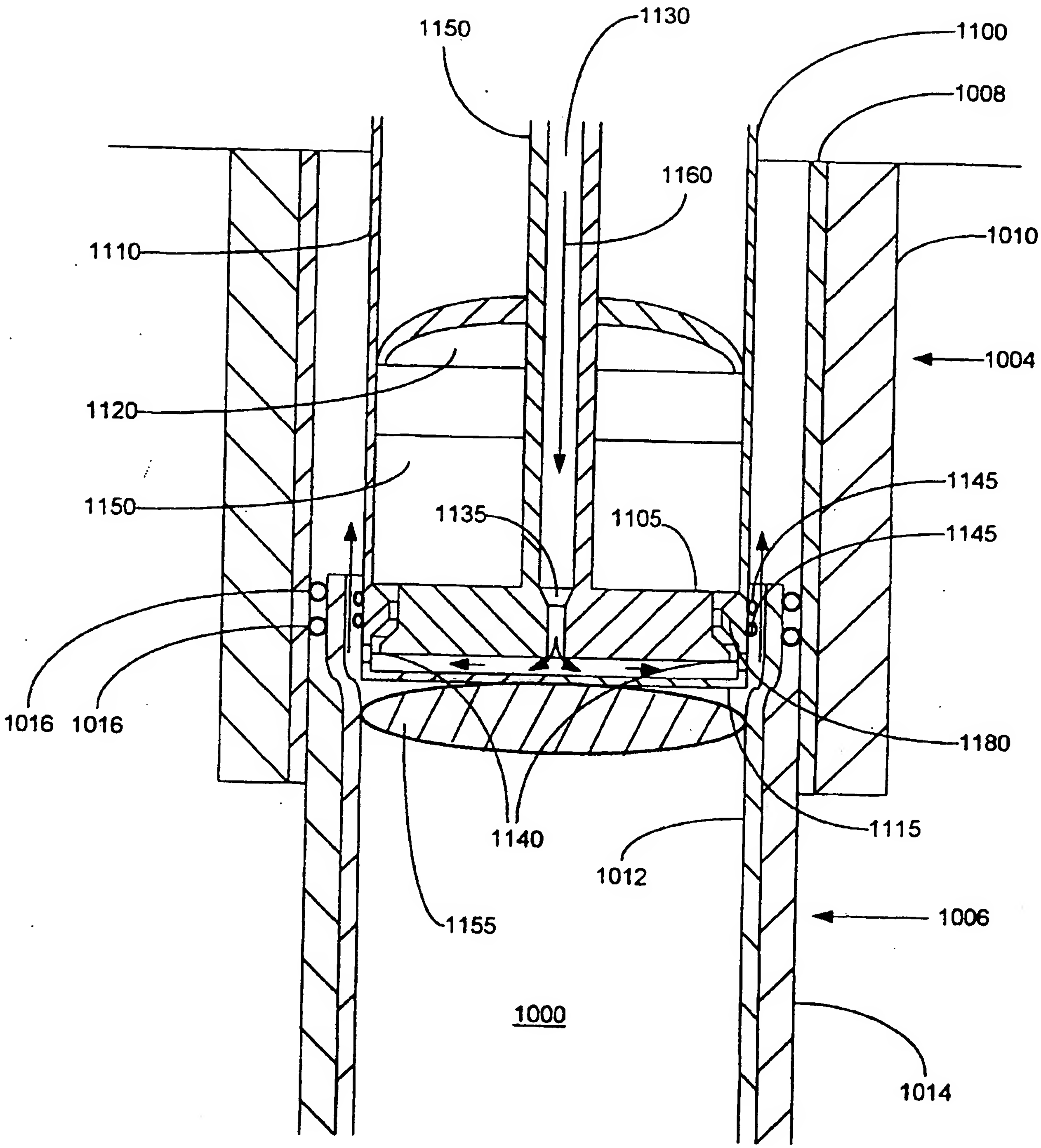
1135
1105
1145
1016
1016
1180
1140
1115
1012
1155
1006
1000
1014

FIGURE 10b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1004
1120
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1105
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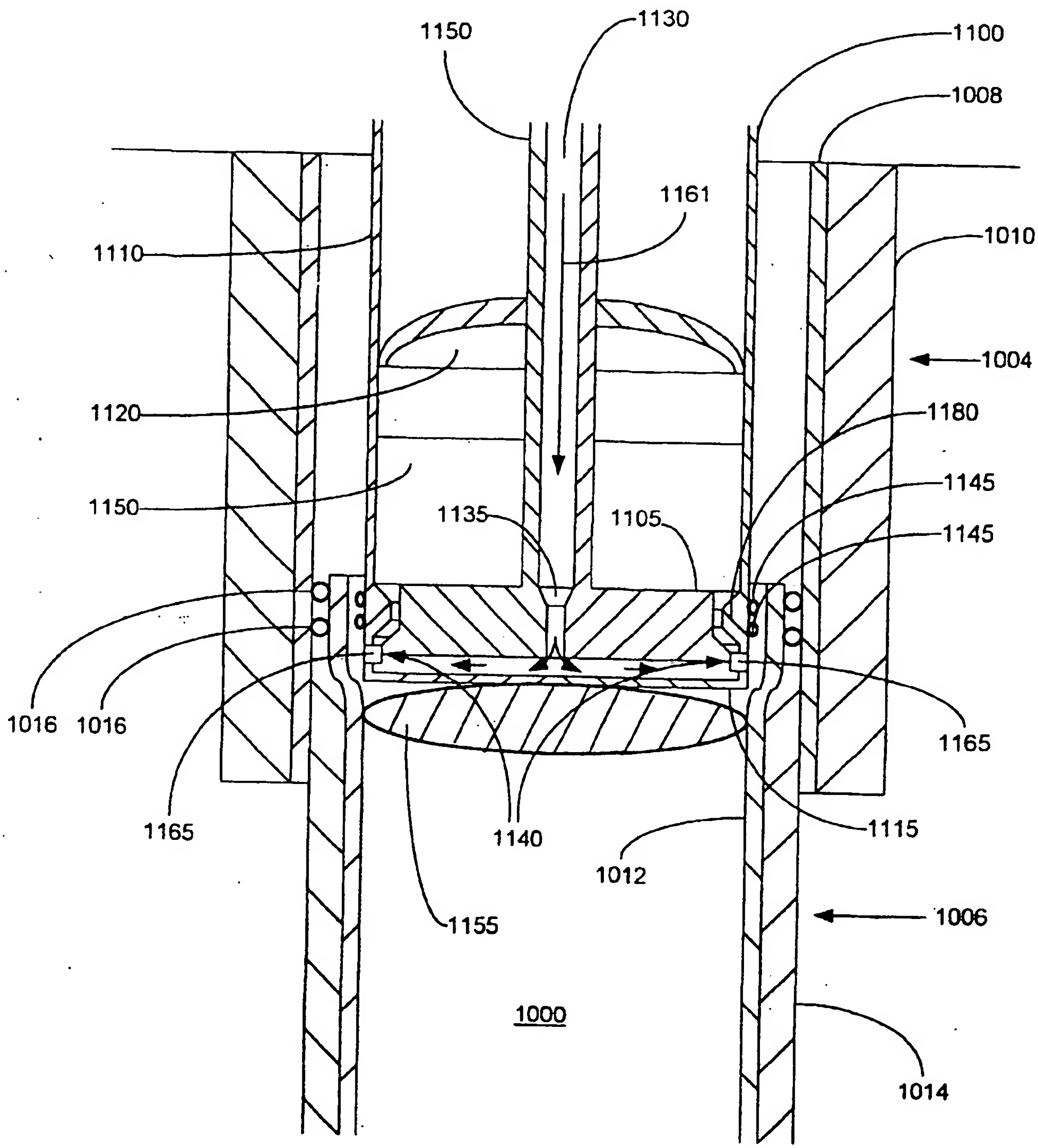
1016
1016
1180
1140
1115
1012
1155
1006
1000
1014

FIGURE 10c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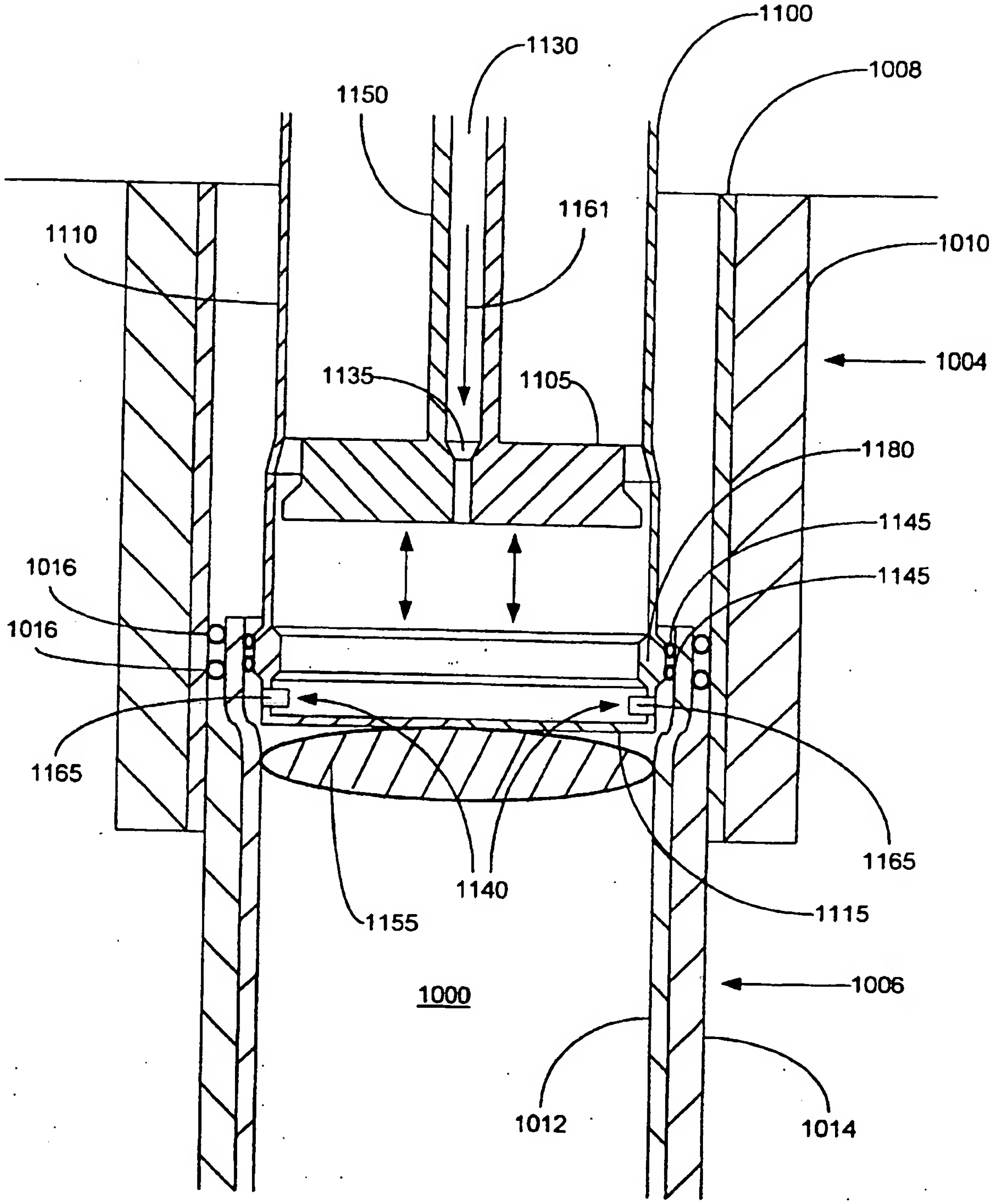
1016
1165
1165
1115
1140
1012
1155
1006
1000
1014

FIGURE 10d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1010
1004
1135
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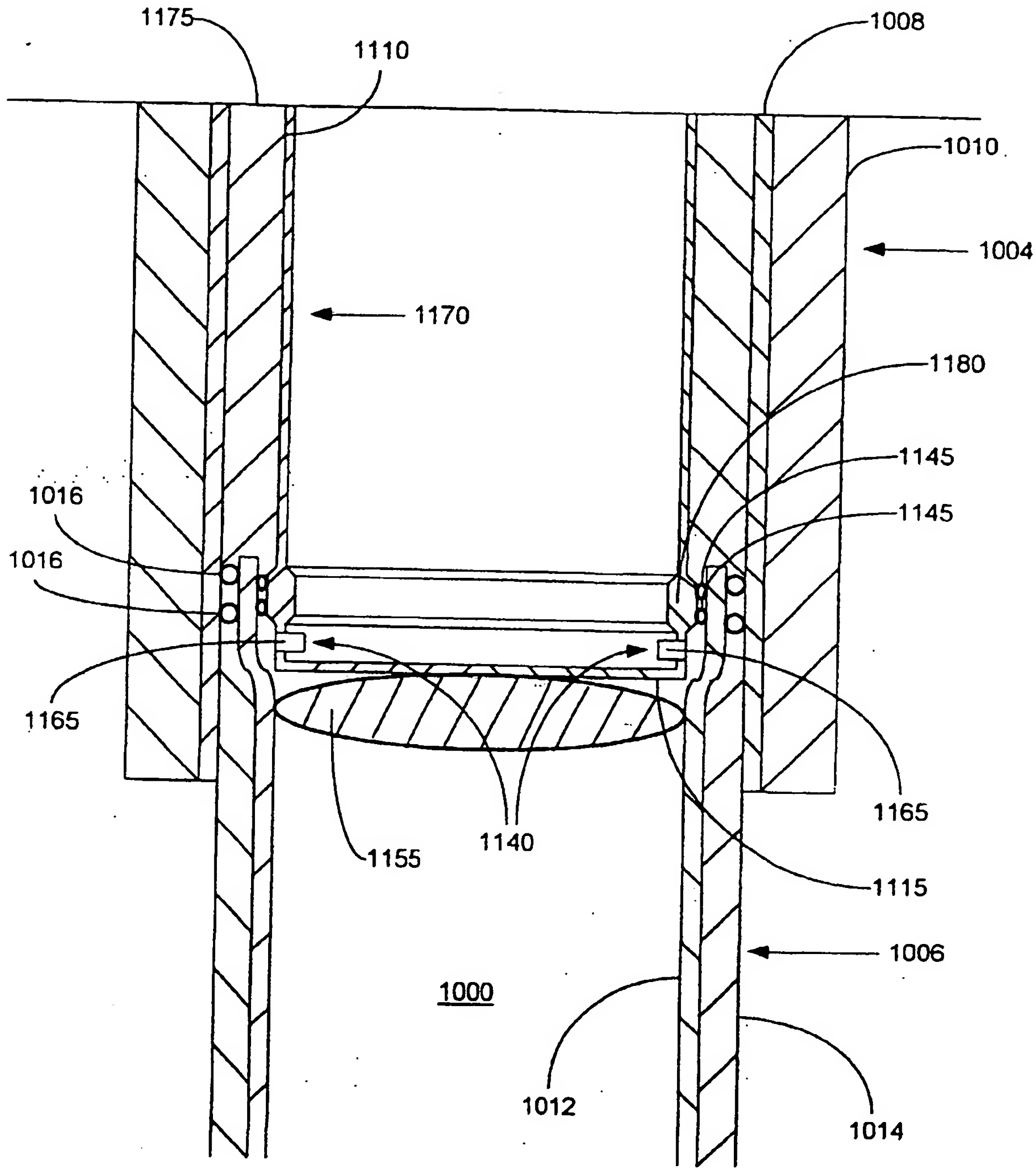
1145
1016
1016
1165
1165
1140
1115
1155
1000
1006
1012
1014

FIGURE 10e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1170
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1145
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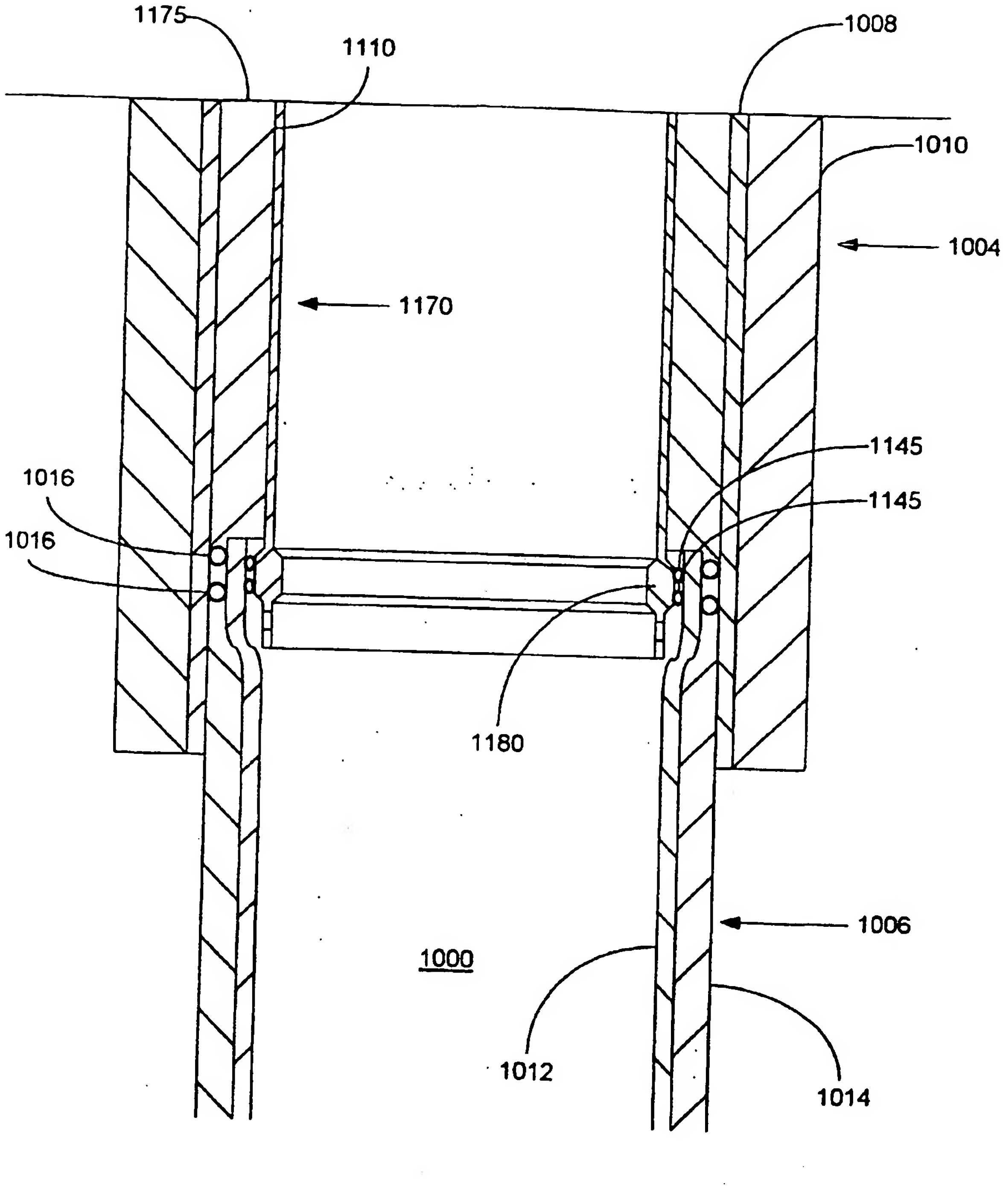
1016
1016
1165
1165
1155
1140
1115
1006
1000
1012
1014

FIGURE 10f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1170
1145
1145
1016
1016
1016
1180
1006
1000
1012
1014

FIGURE 10g

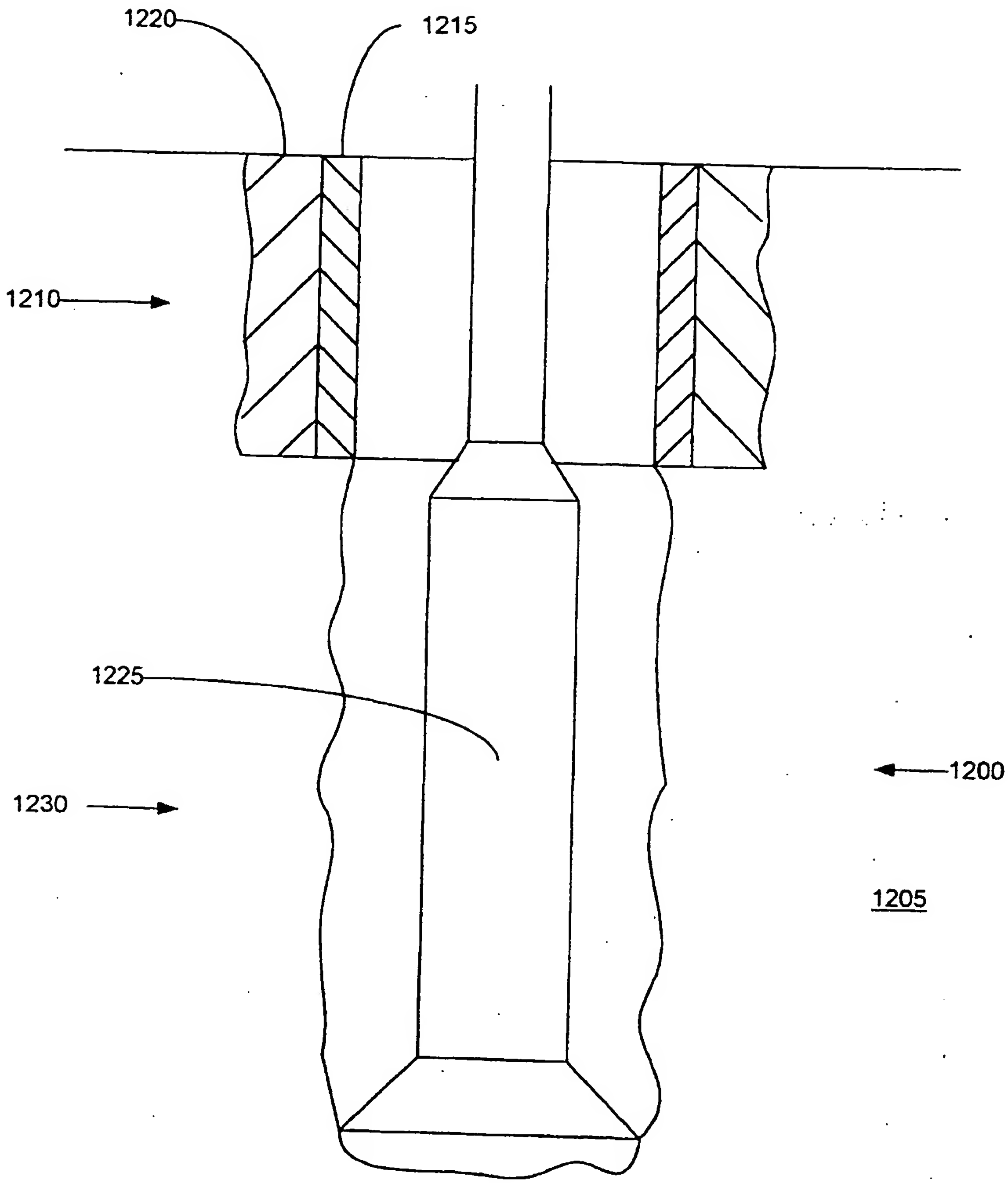
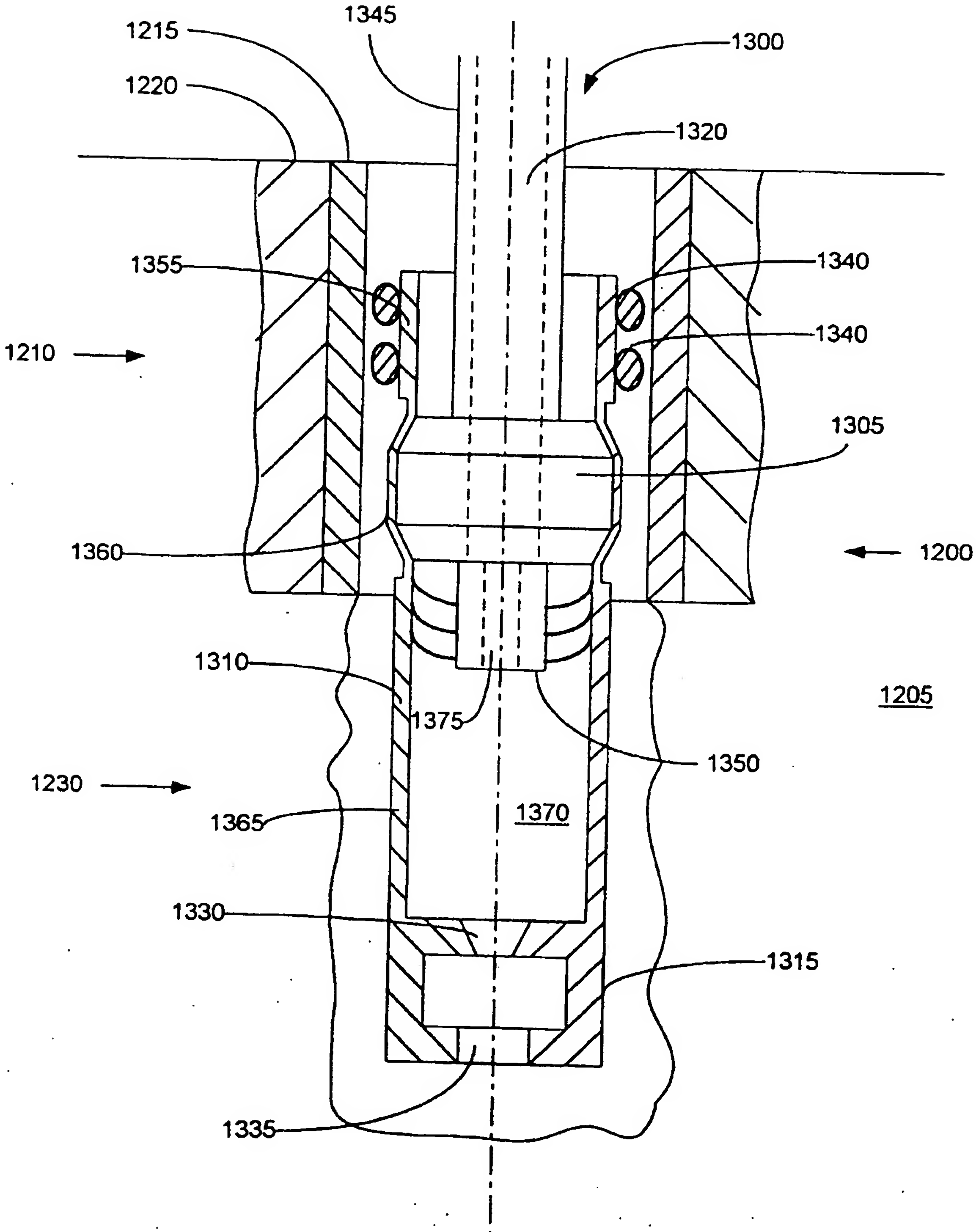


FIGURE 11a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1300
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1355
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1340
1210
1305
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1200
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1350
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1365
1370
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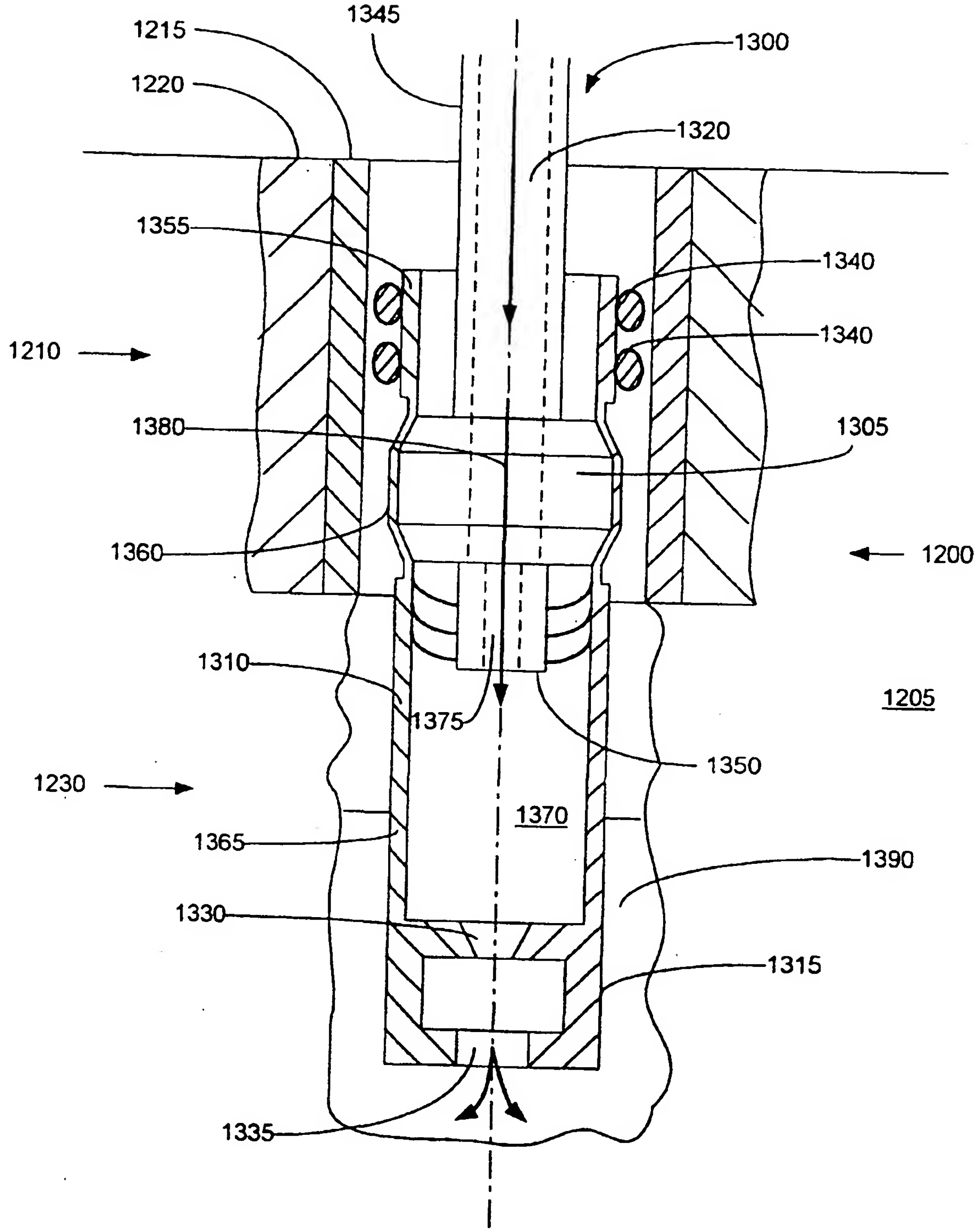
1335

FIGURE 11b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1215
1300
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1320
1355
1340
1340
1210
1380
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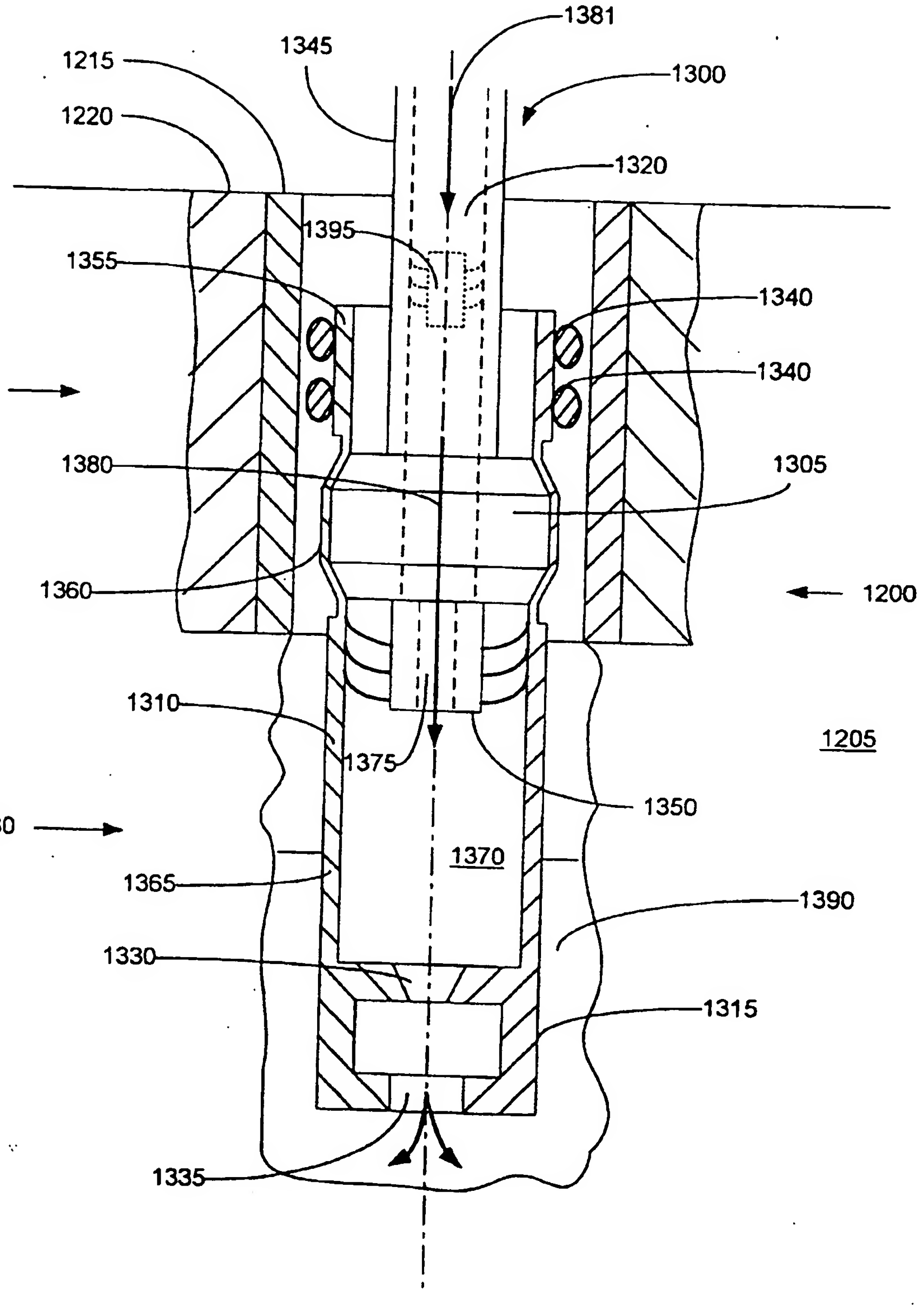
1360
1200
1310
1205
1375
1350
1230
1370
1365
1390
1330
1315
1335

FIGURE 11c



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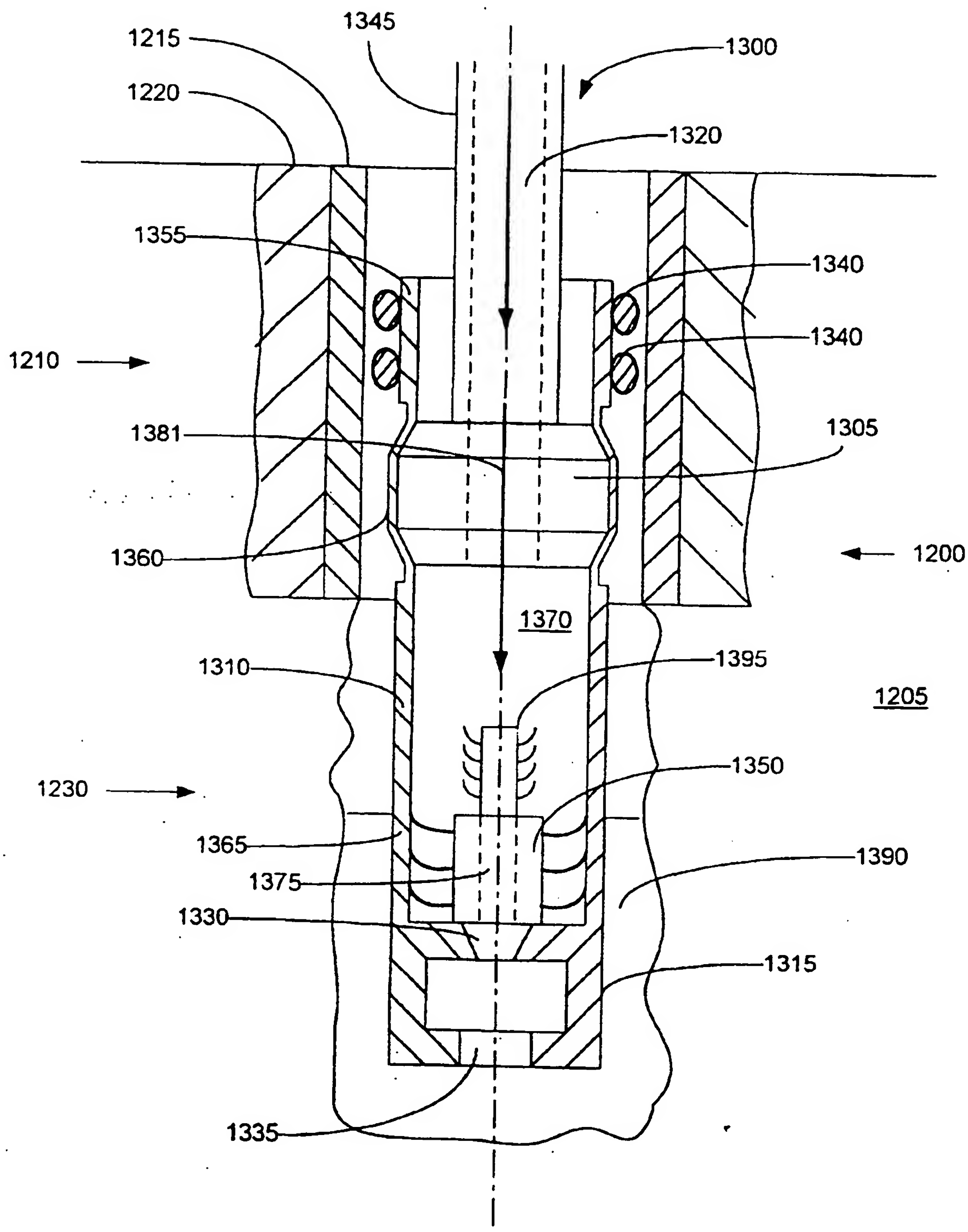
1220
1320
1395
1355
1340
1340
1210
1380
1305
1360
1200
1310
1205
1375
1350
1230
1370
1365
1390
1330
1315
1335

FIGURE 11d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1215
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1320
1355
1340
1340
1210
1381
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1200
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1205
1350
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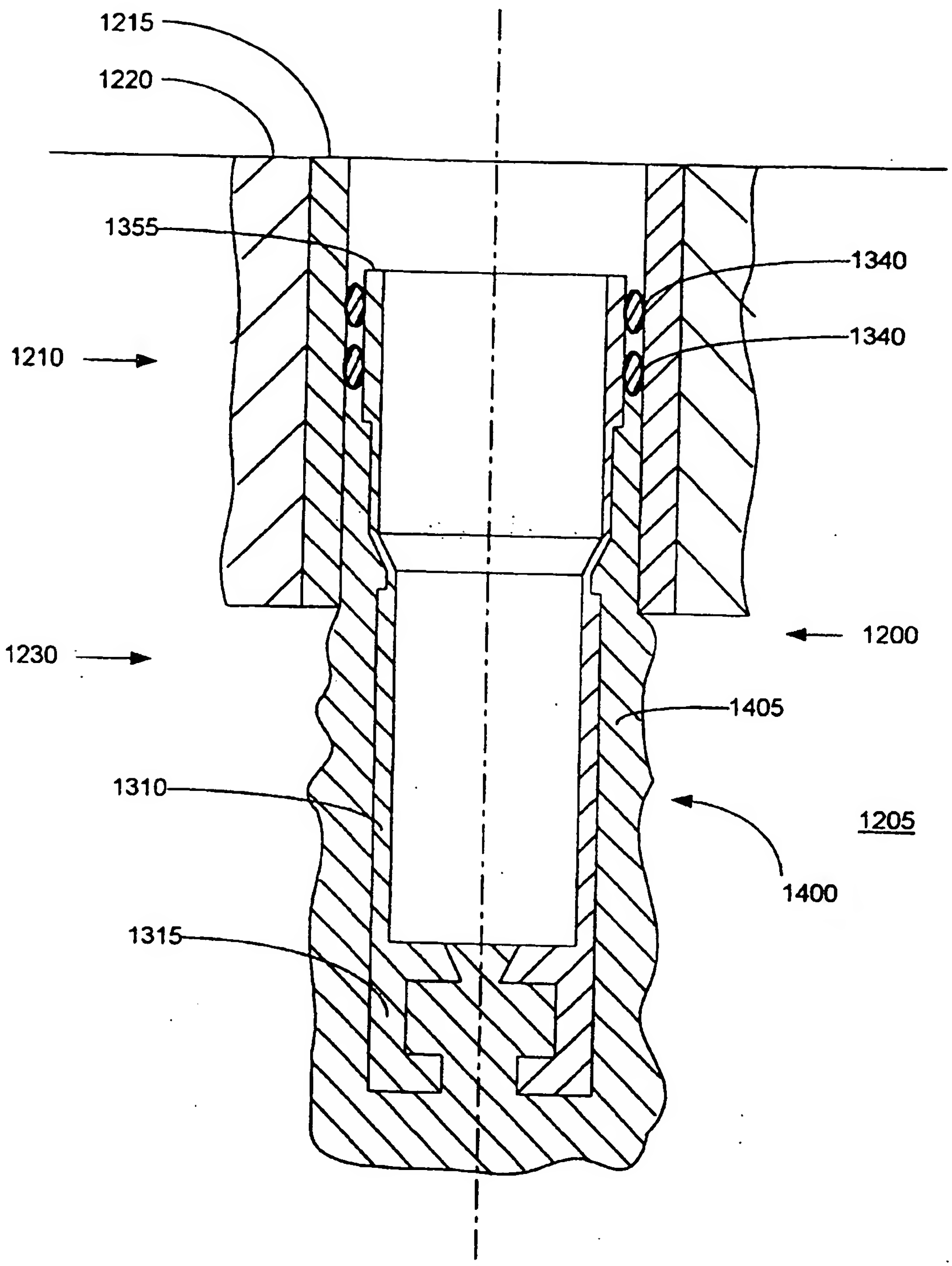
1365
1390
1375
1330
1315
1335

FIGURE 11e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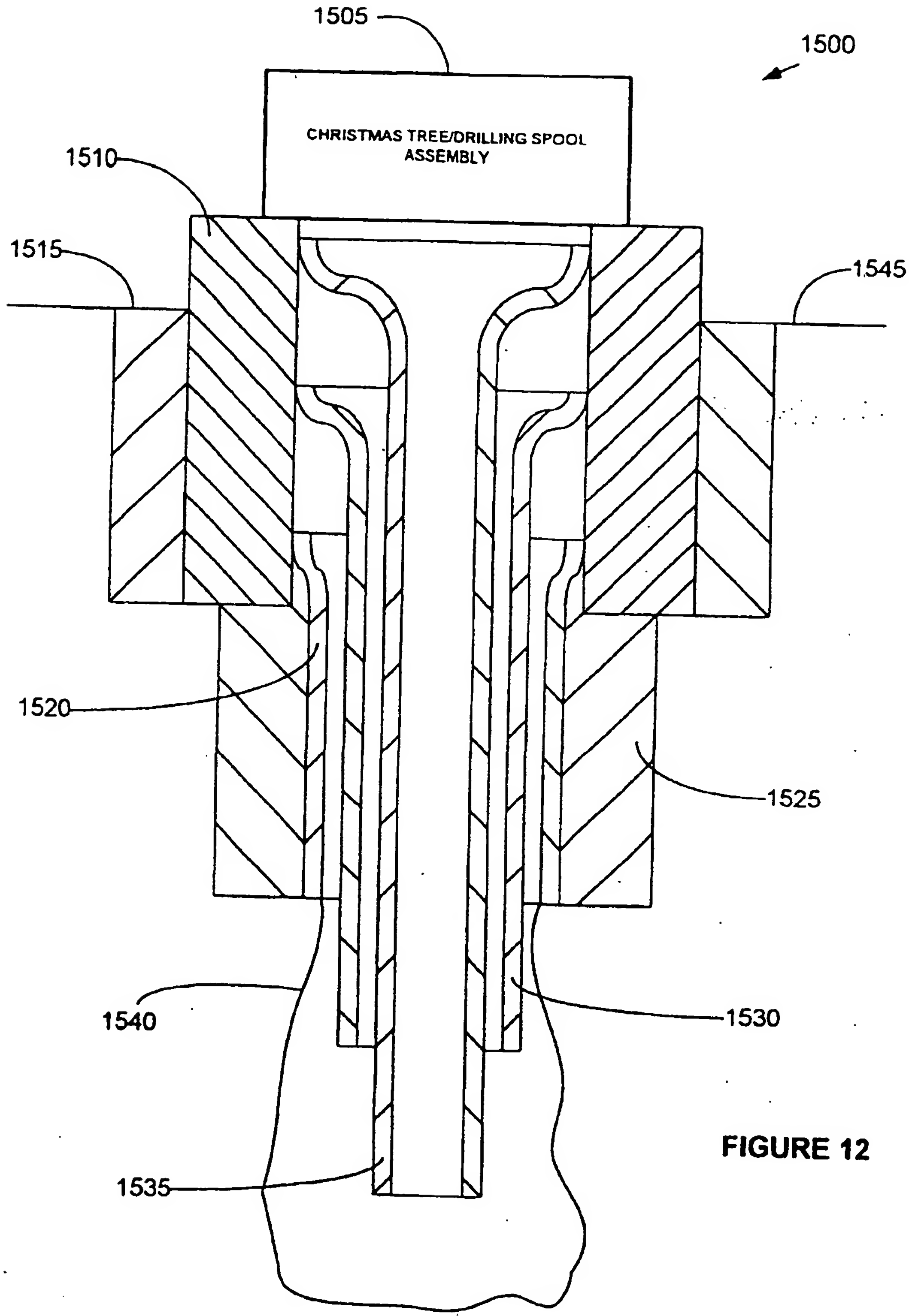
1310
1205
1400
1315

FIGURE 11f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1500
CHRISTMAS TREE/DRILLING SPOOL ASSEMBLY
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1530
1535

FIGURE 12

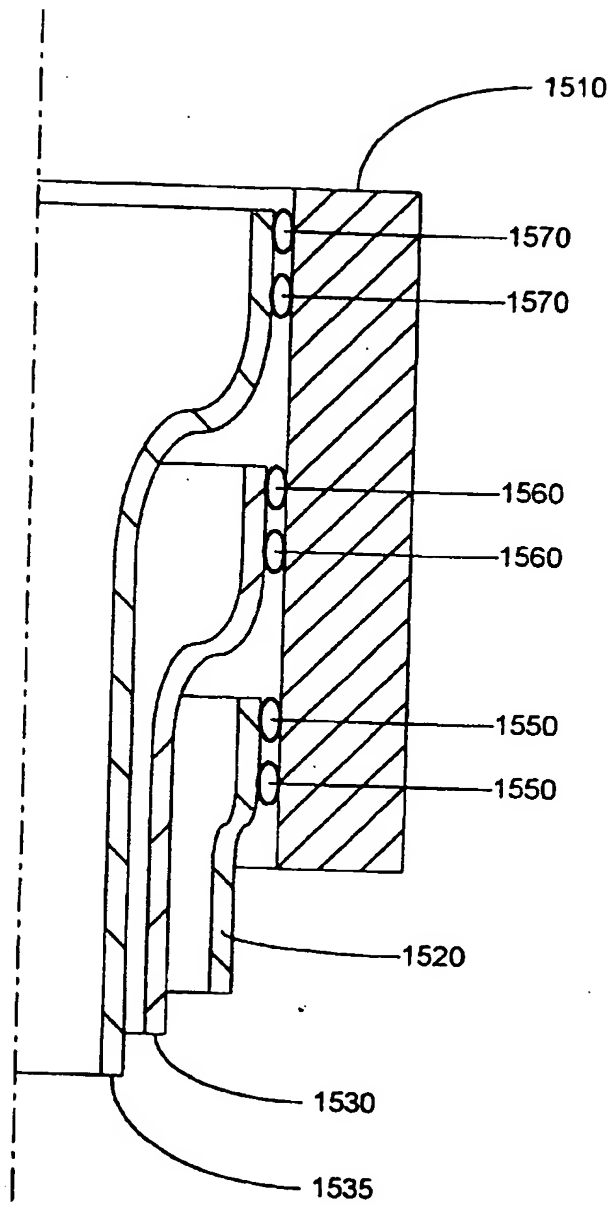


FIGURE 13

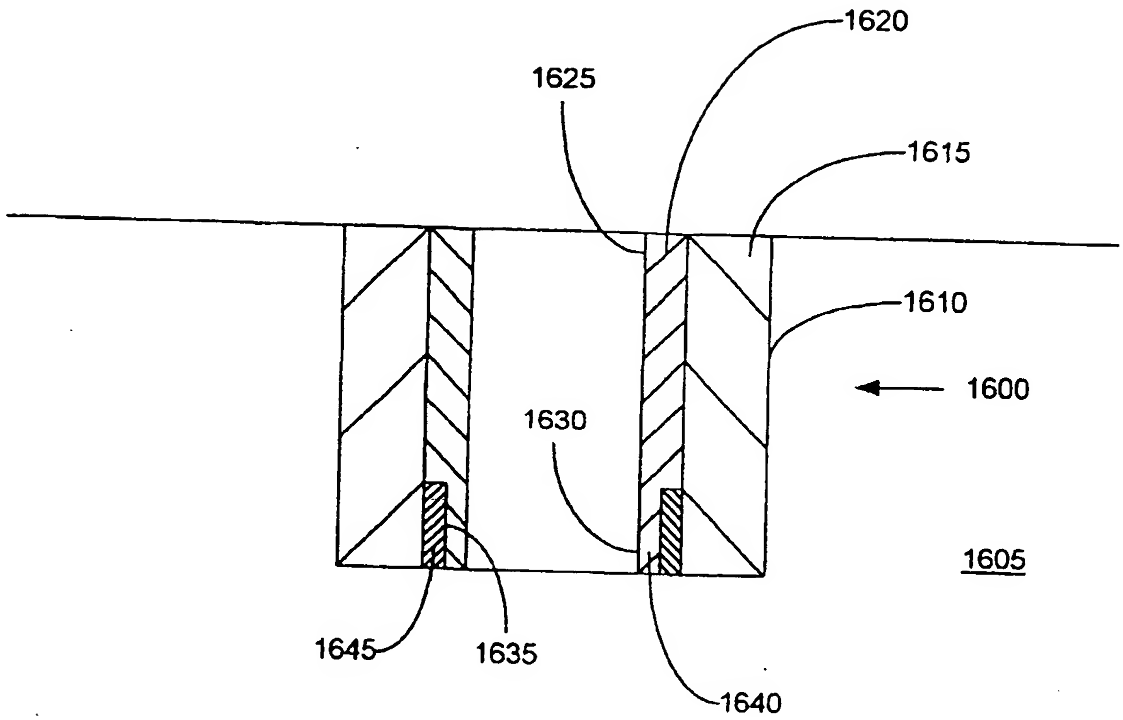


FIGURE 14a

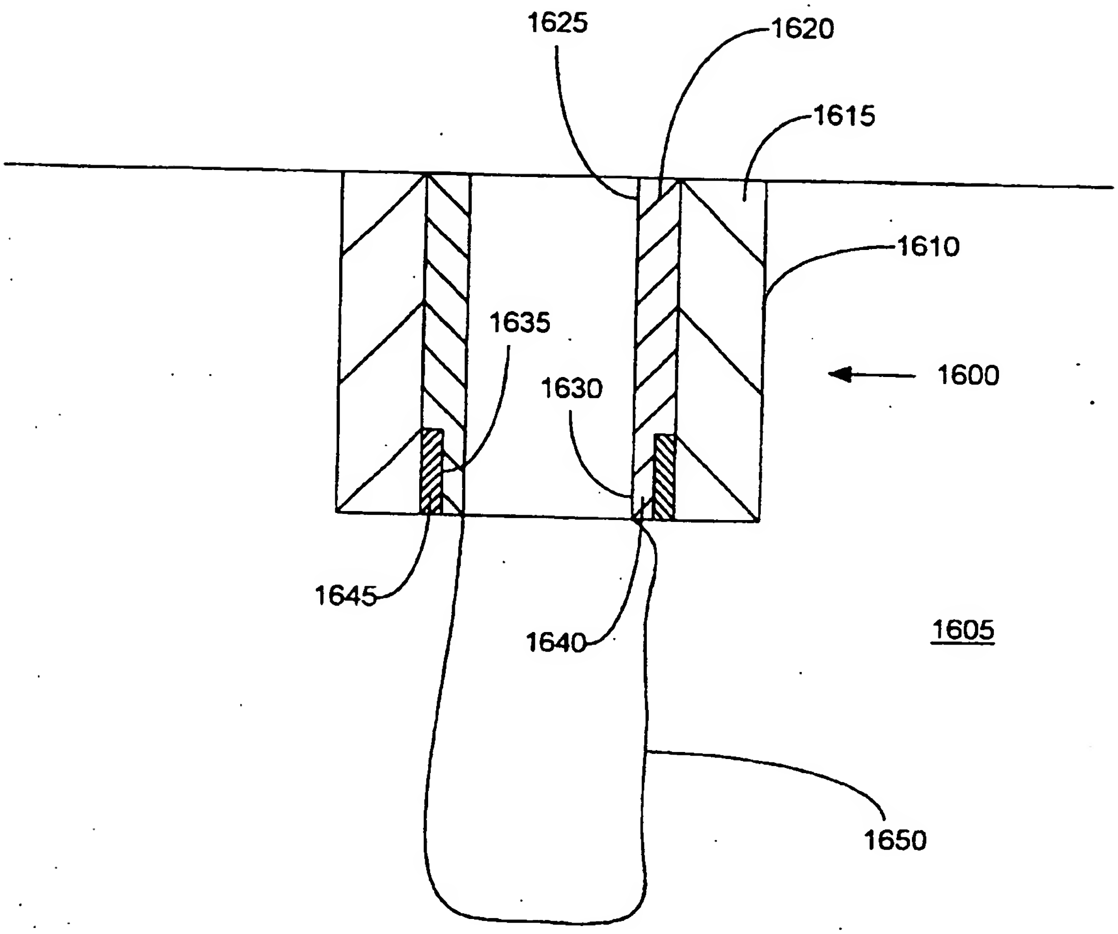
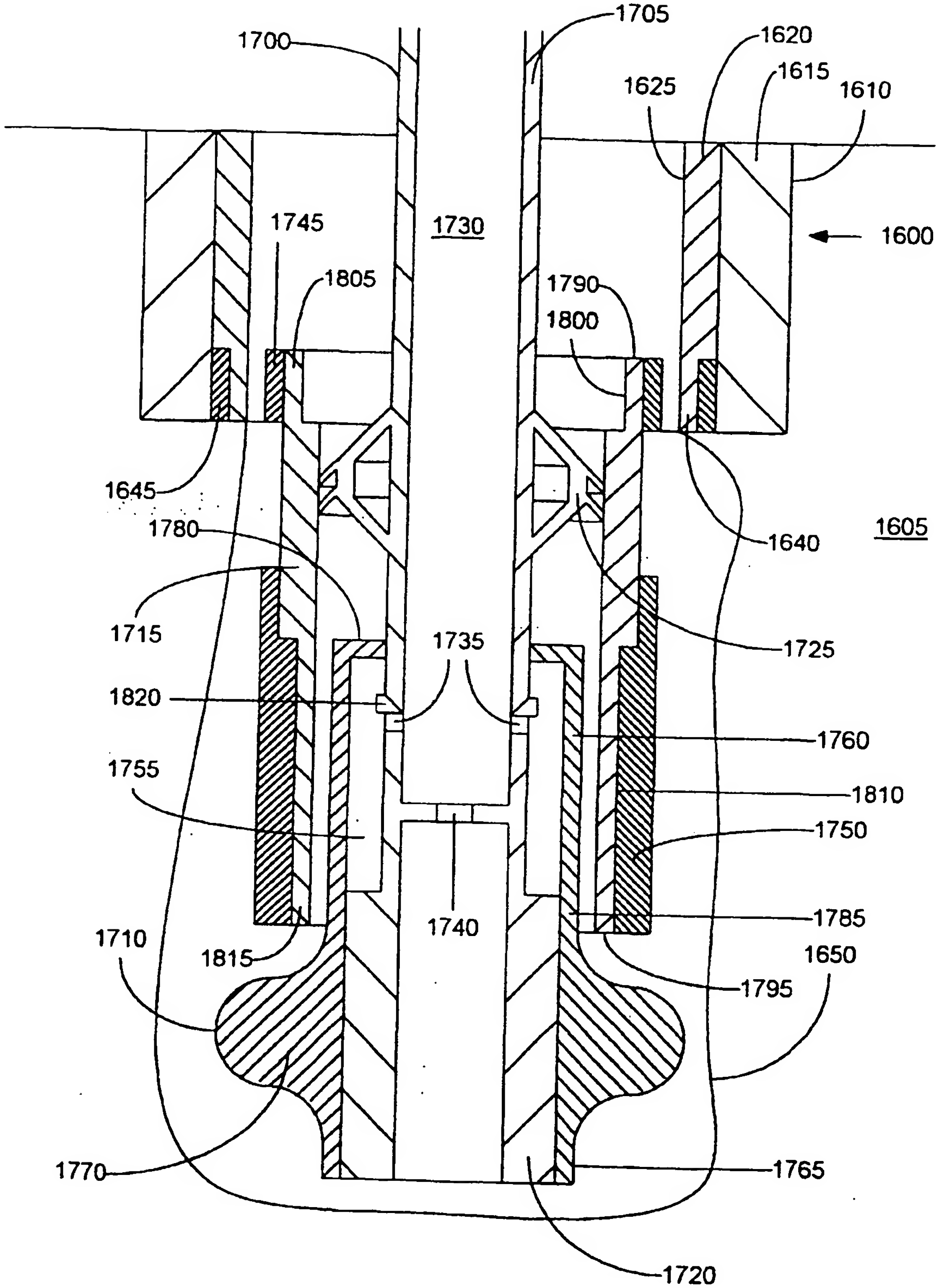


FIGURE 14b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1735
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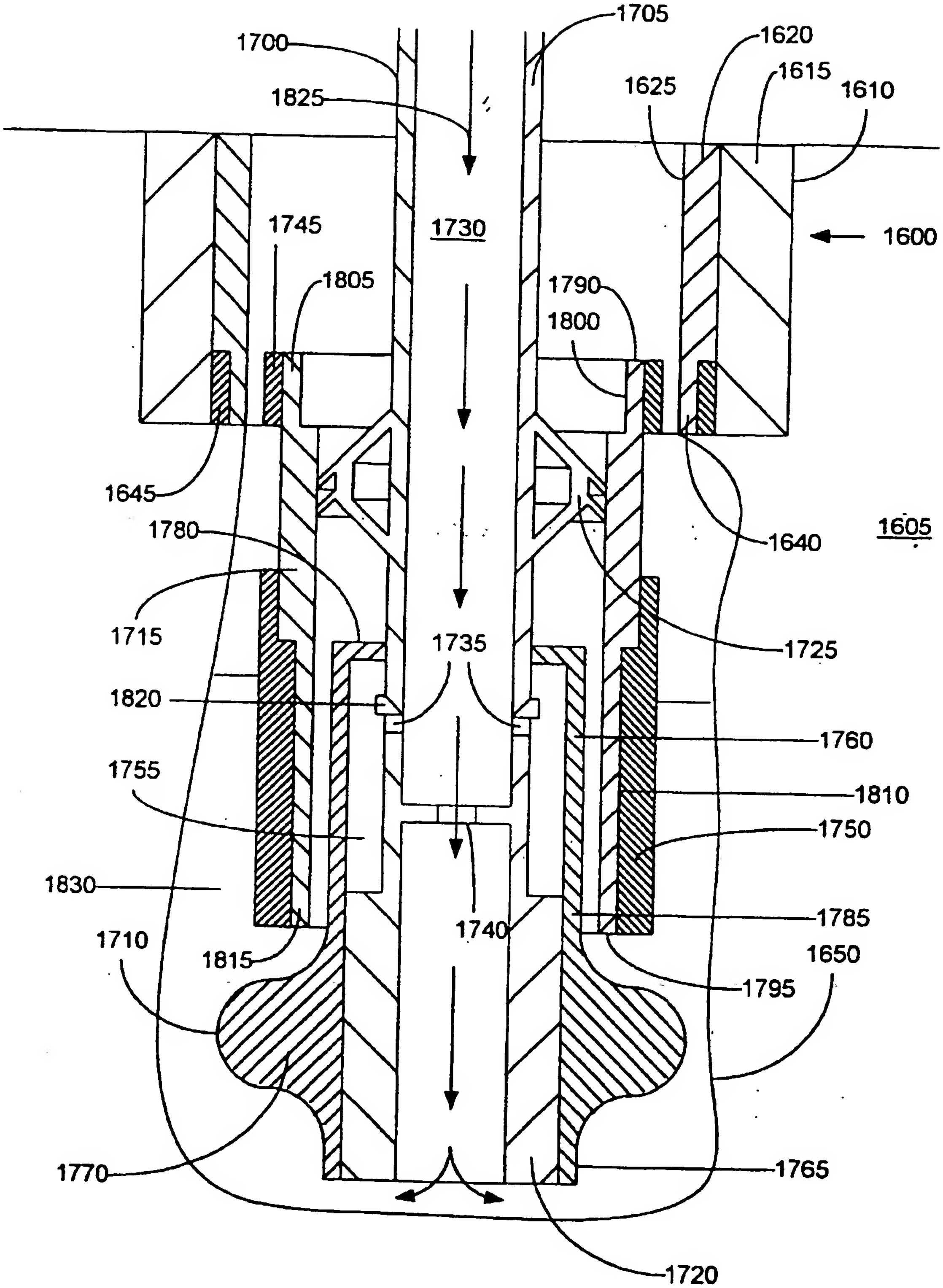
1765
1720

FIGURE 14c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1765
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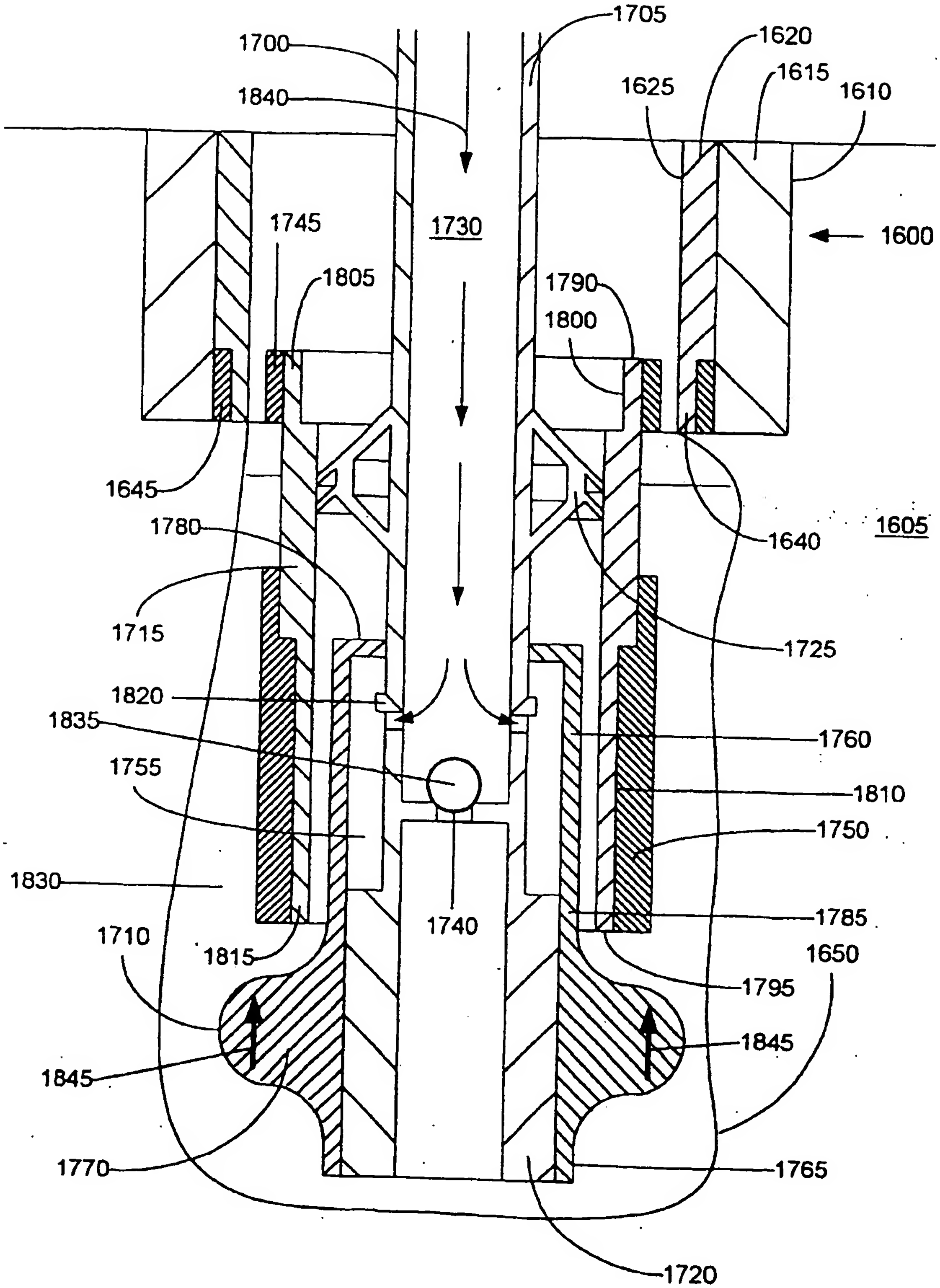
FIGURE 14d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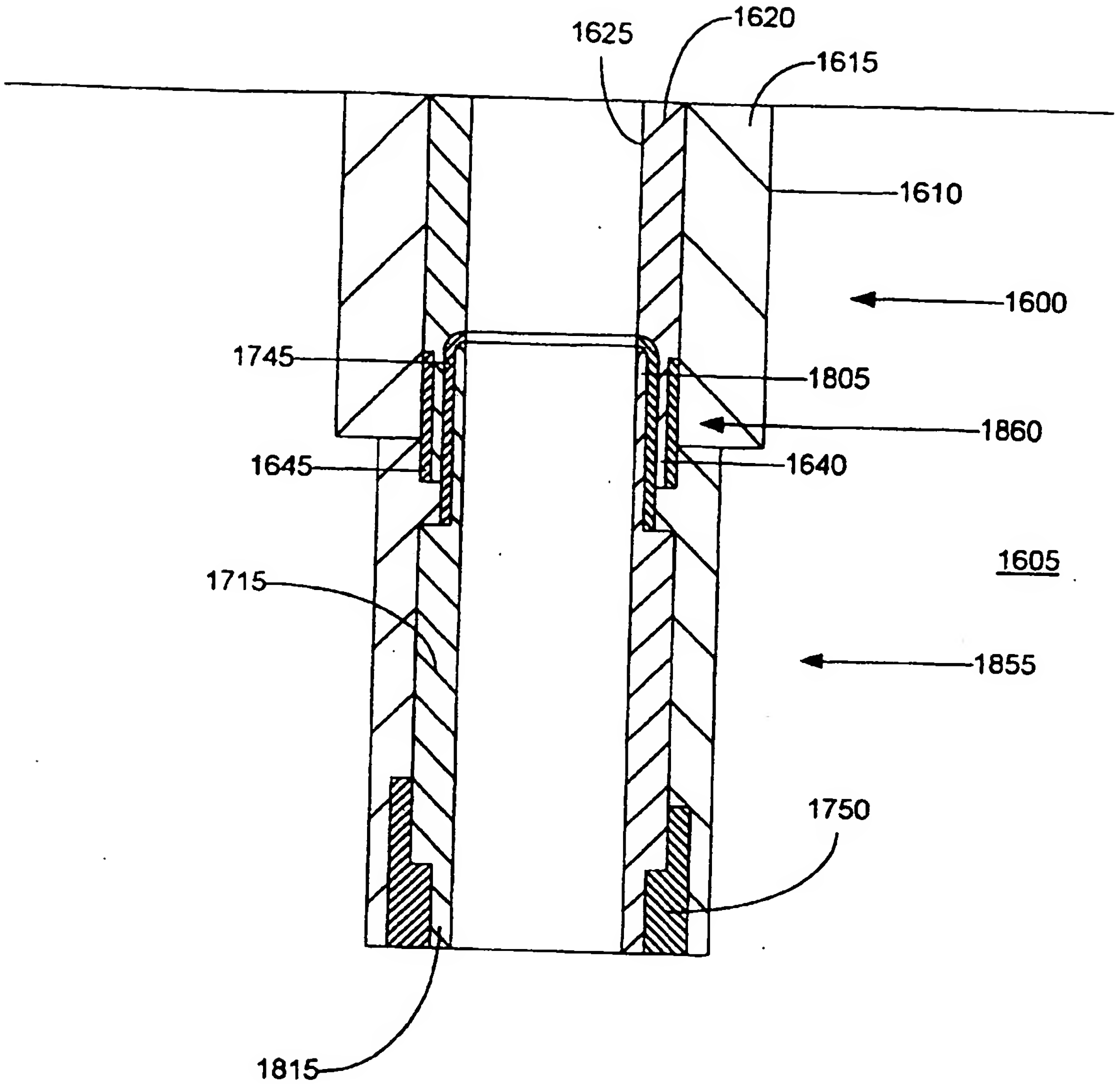
1770
1765
1720

FIGURE 14e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1750
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FIGURE 14f

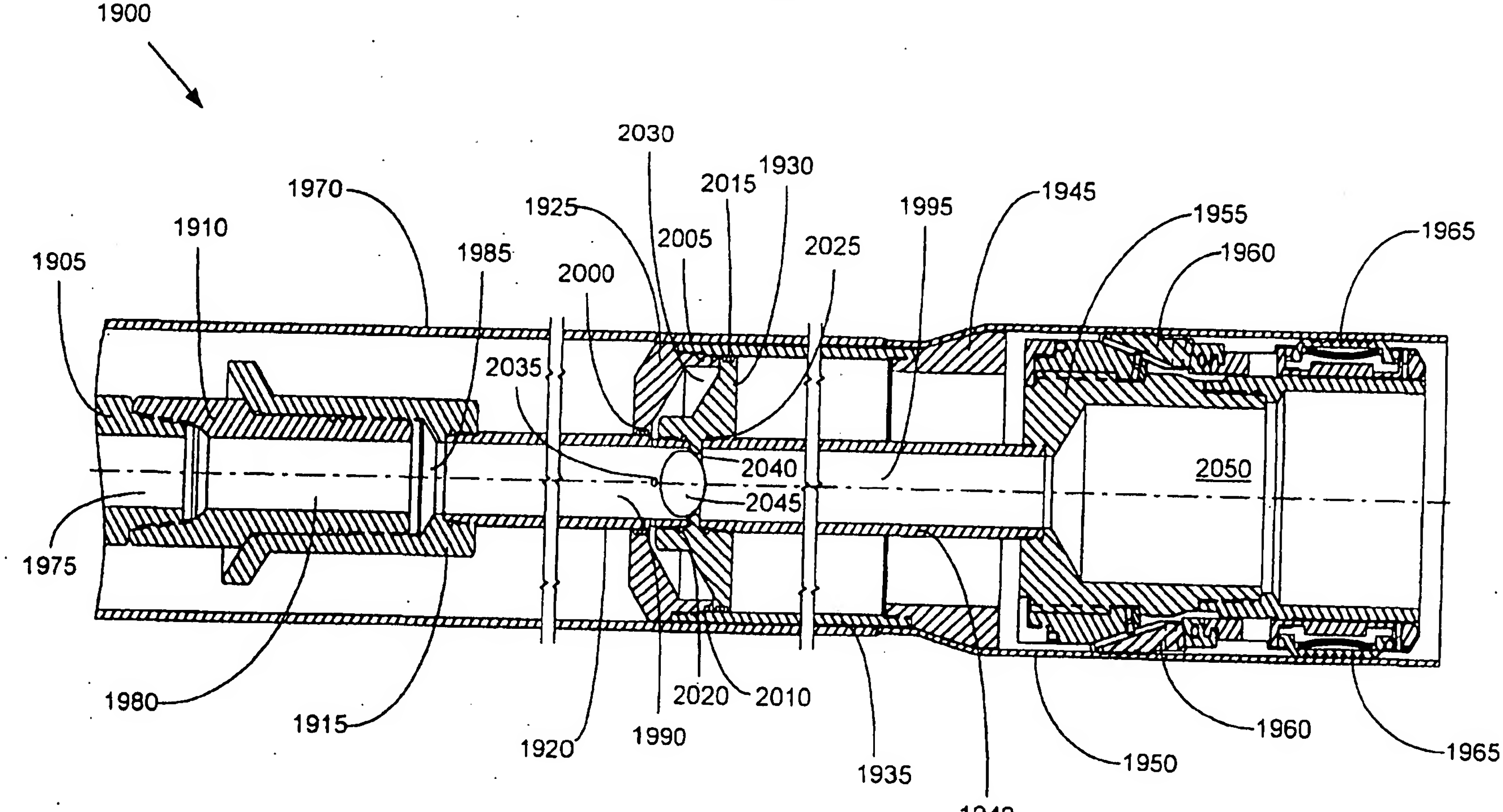
1900
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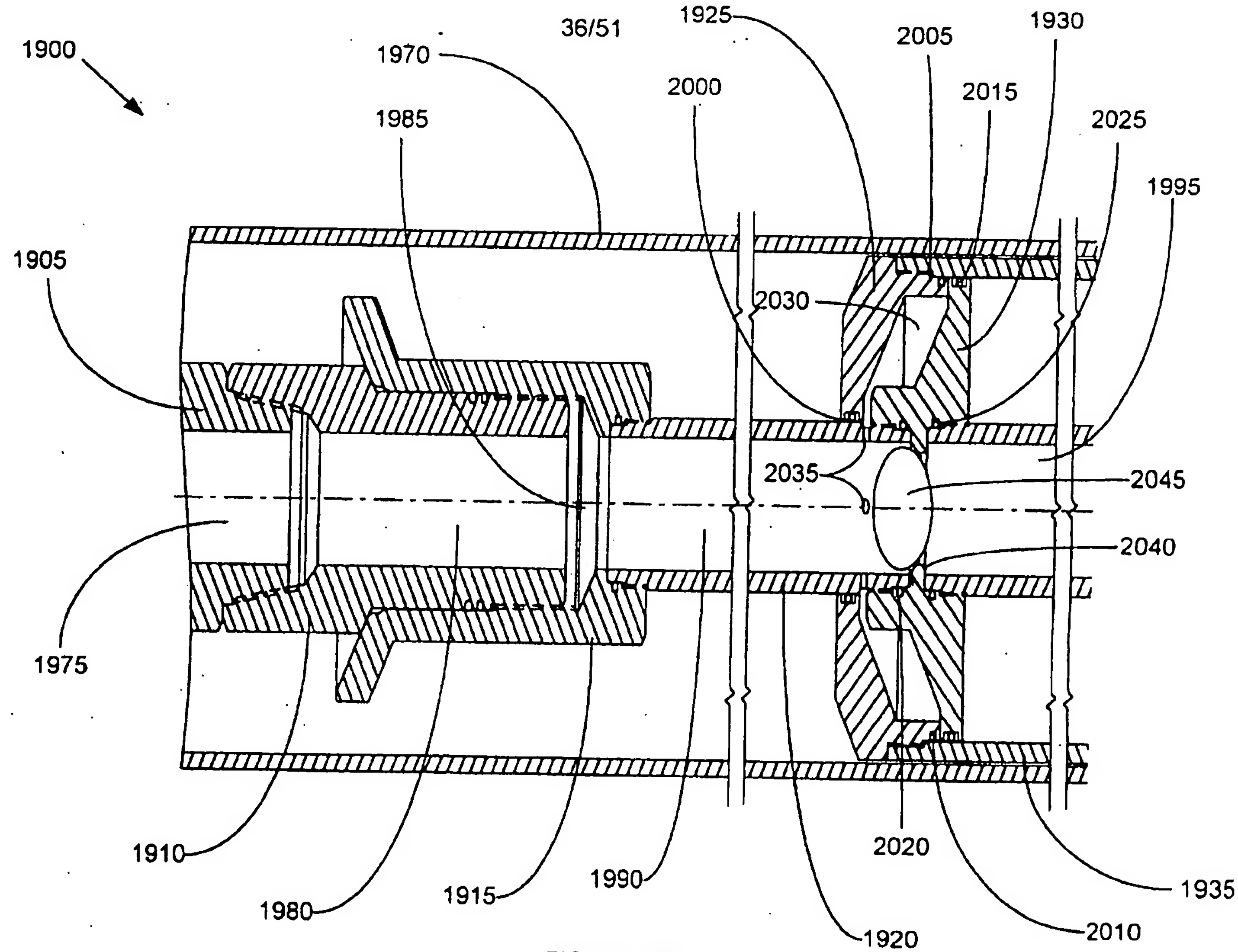
FIGURE 15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1920
2010
1935

FIGURE 15a

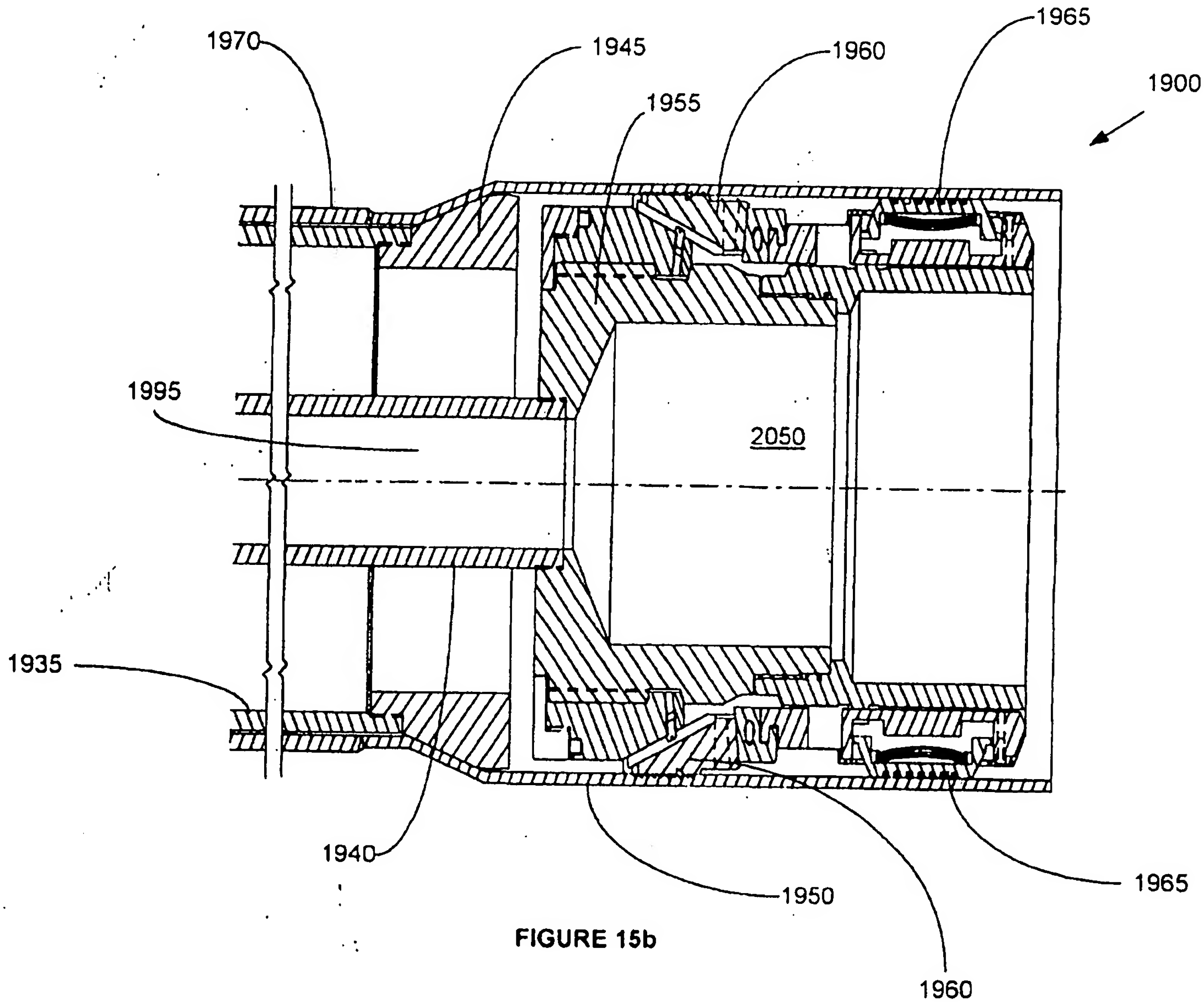
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FIGURE 15b

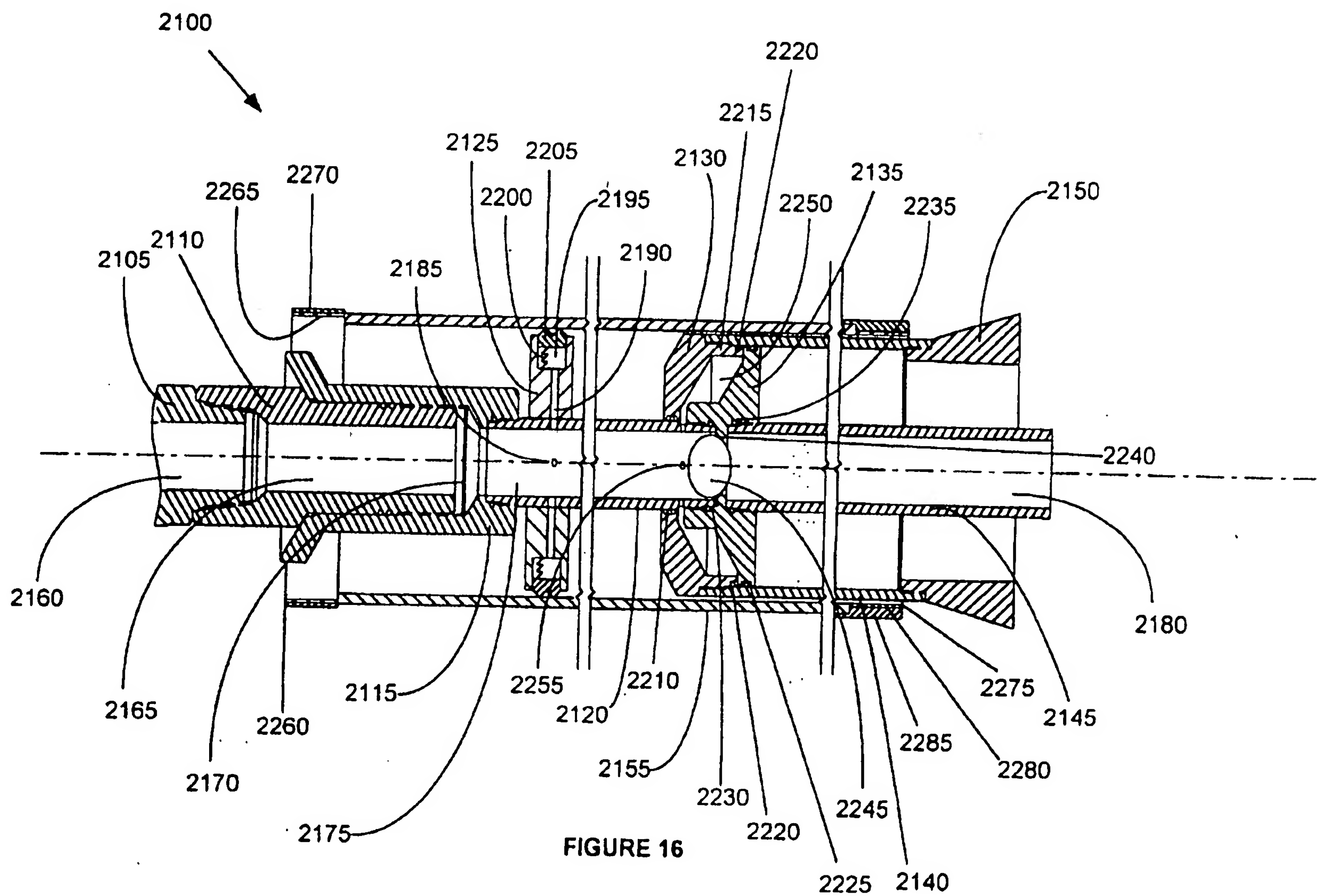

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FIGURE 16

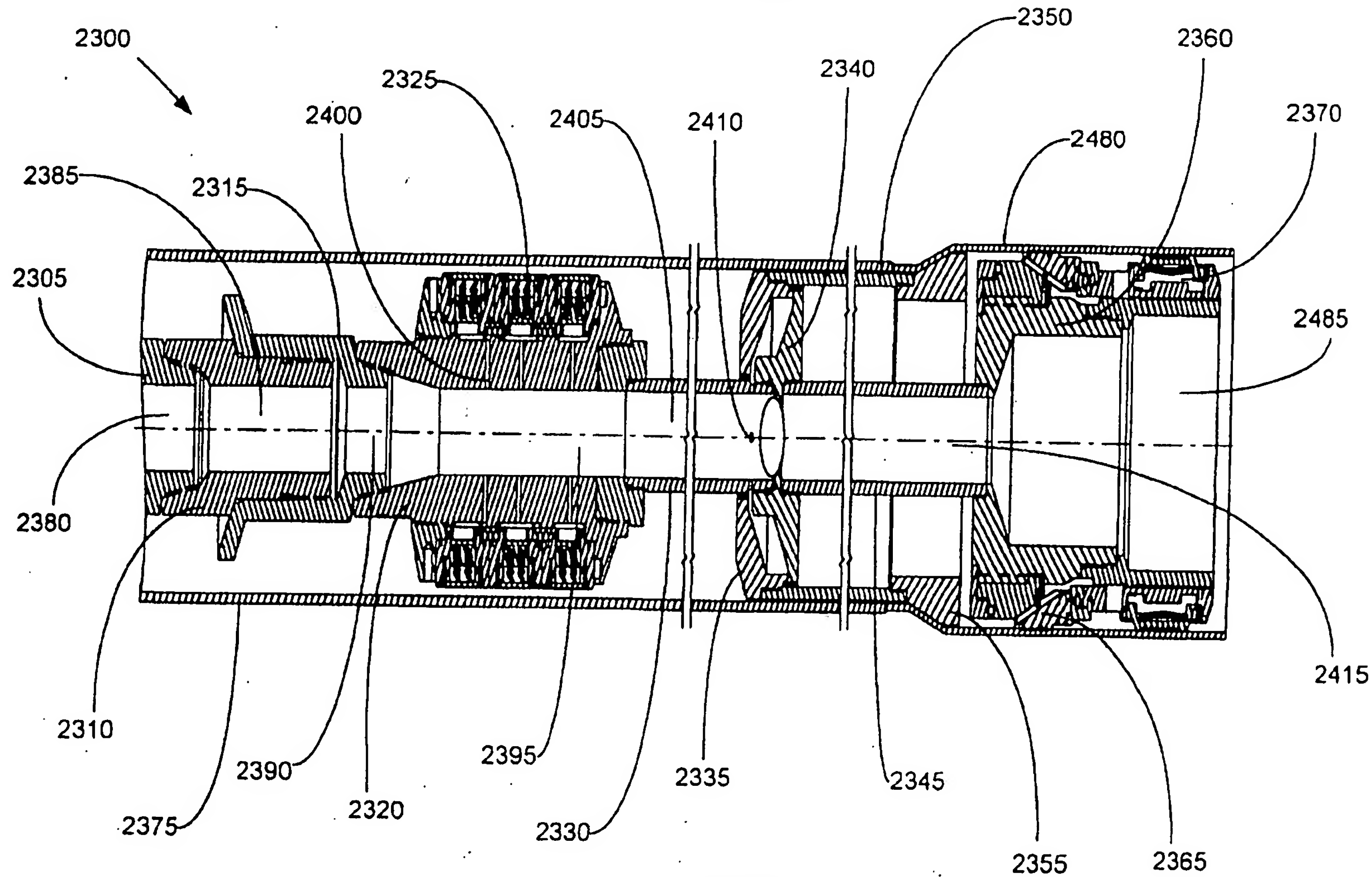
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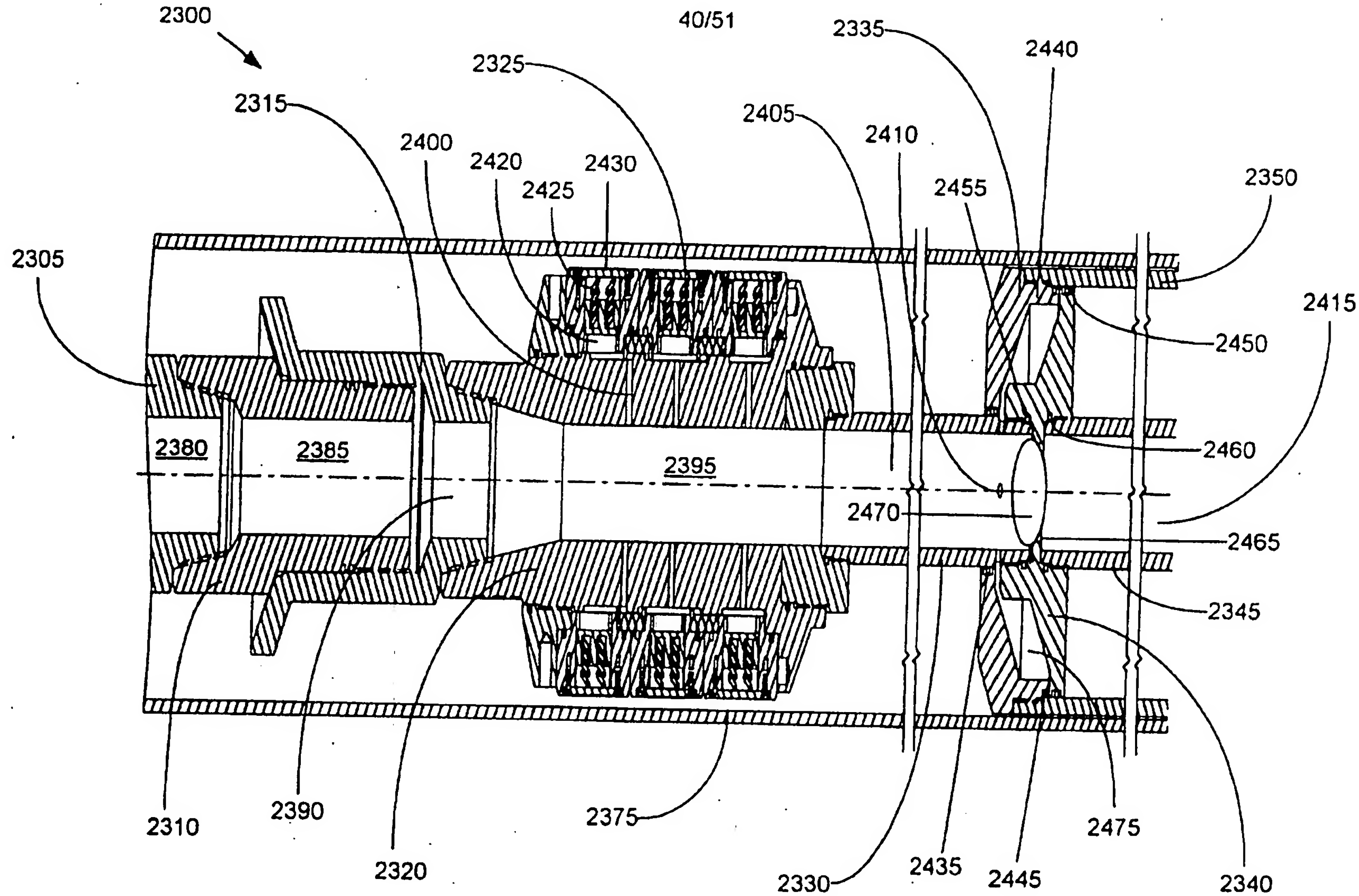
FIGURE 17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2470
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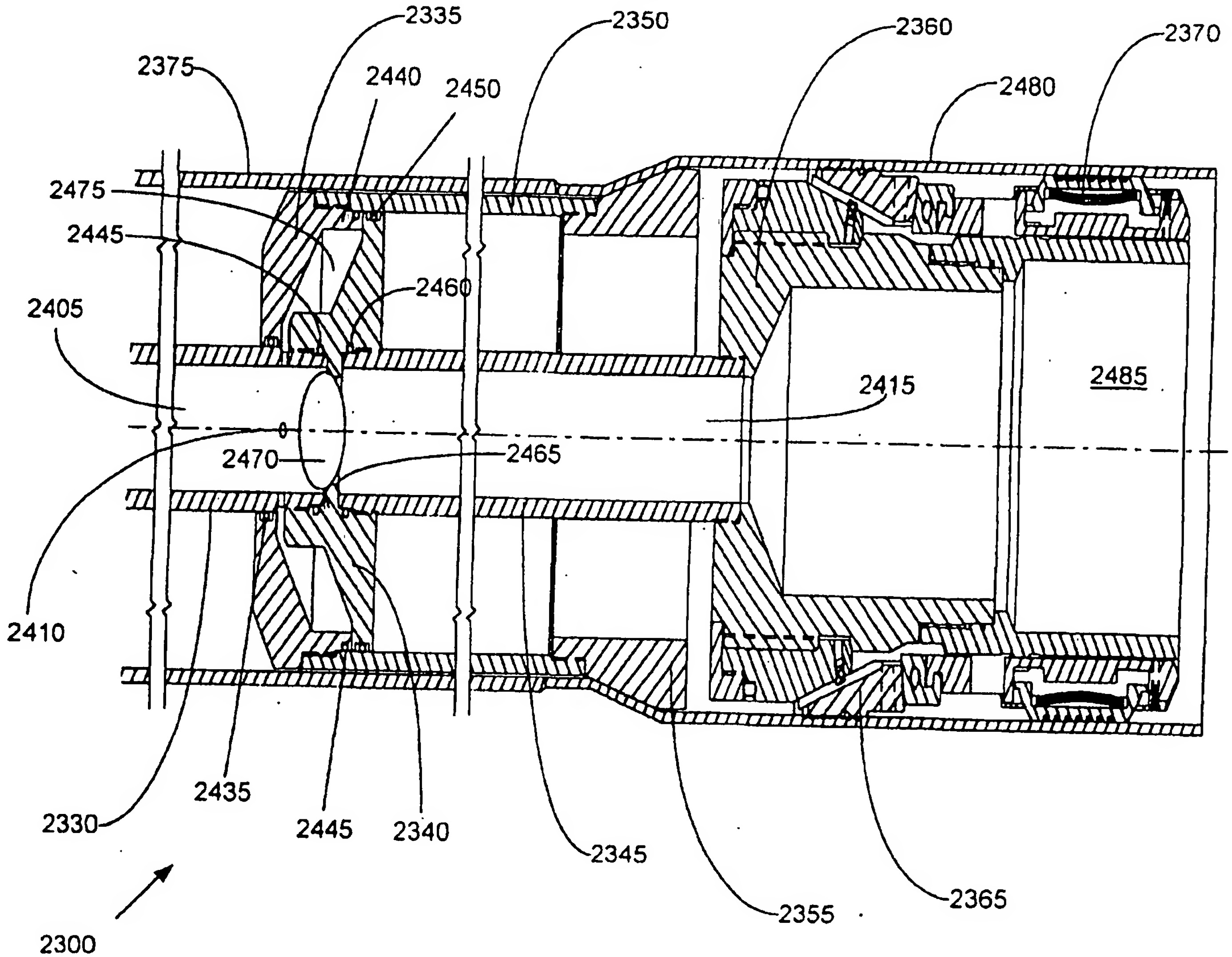
FIGURE 17a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2365
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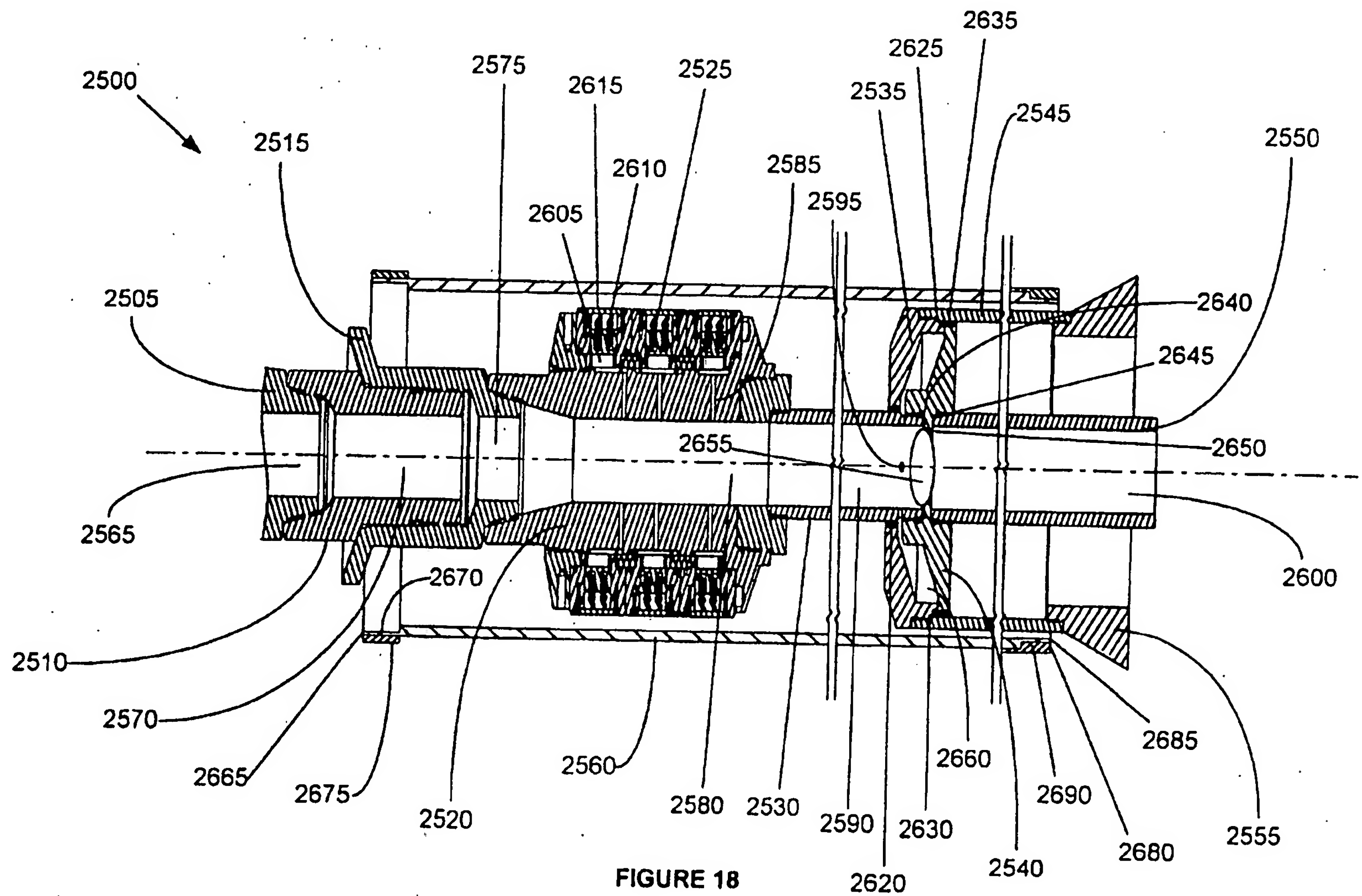
FIGURE 17b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2580
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2670
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2690

FIGURE 18

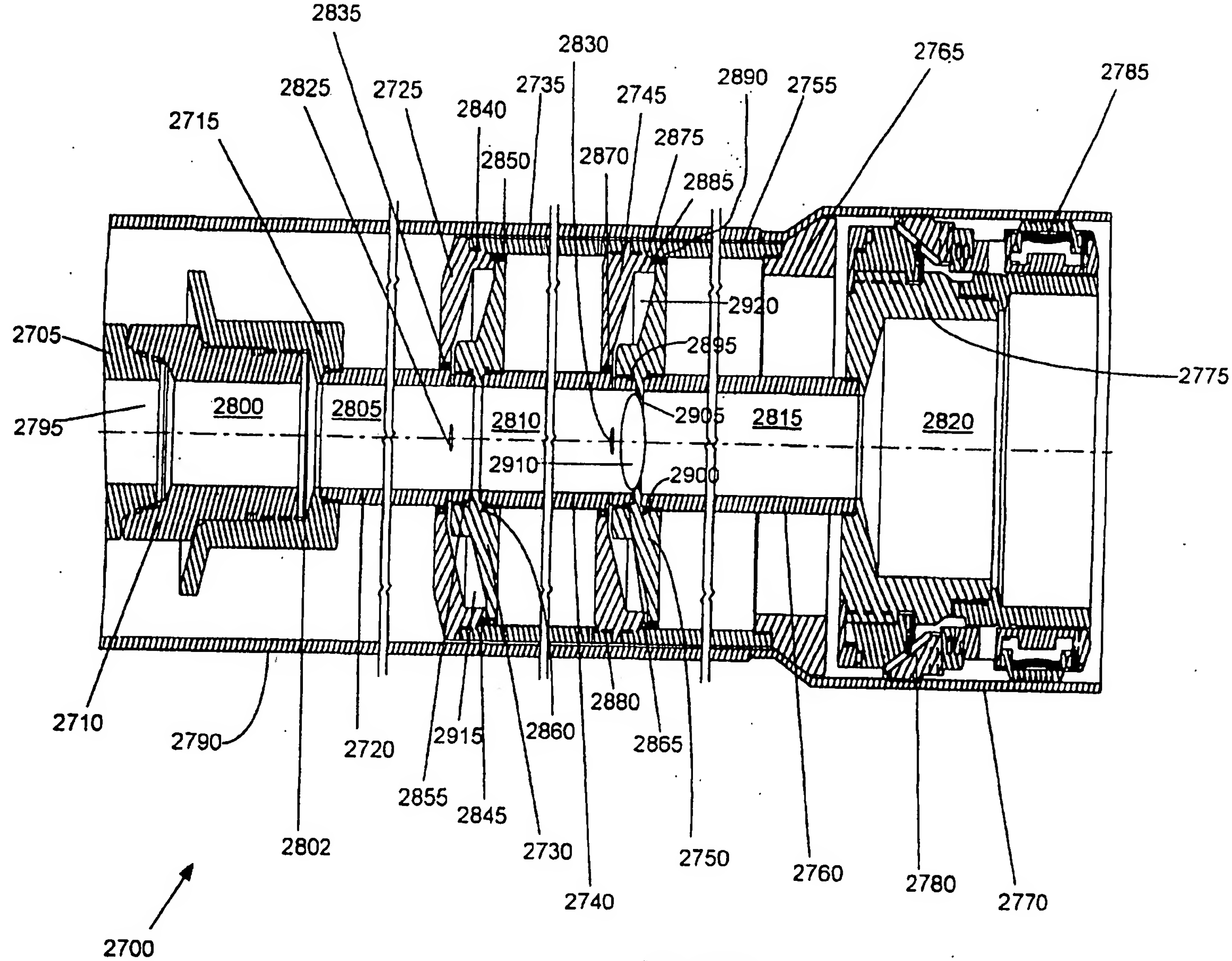
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FIGURE 19

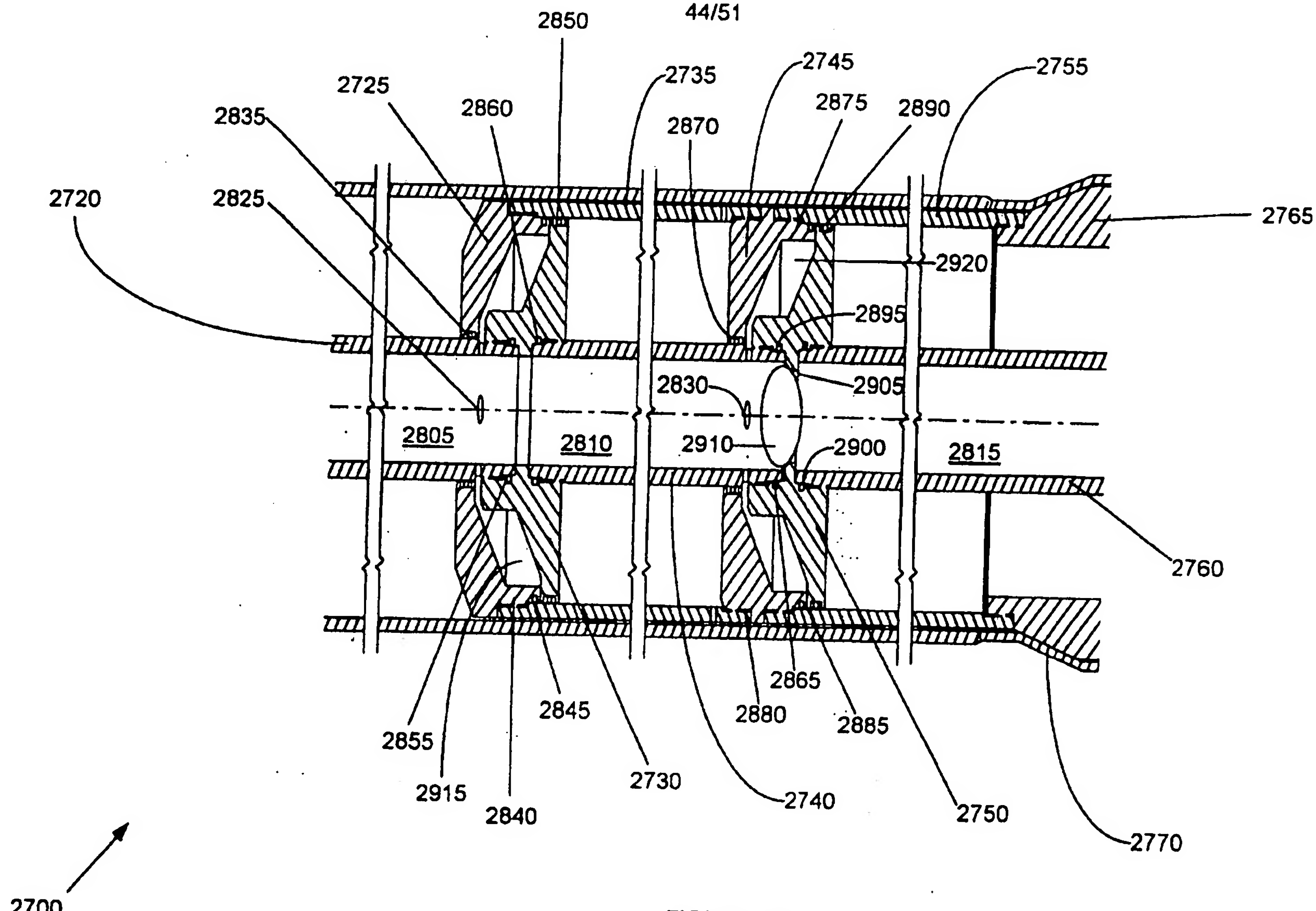
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FIGURE 19a

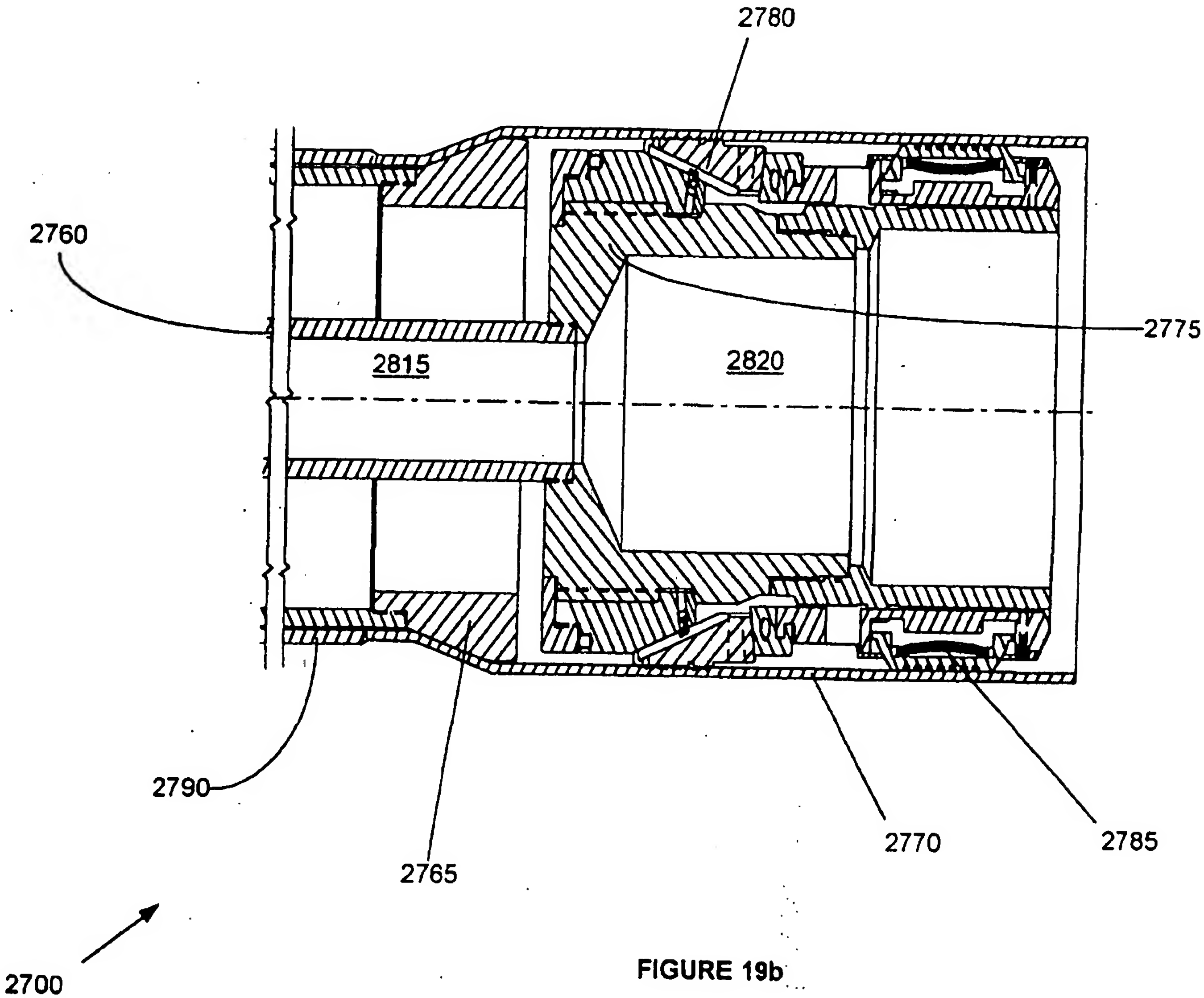

FIGURE 19b

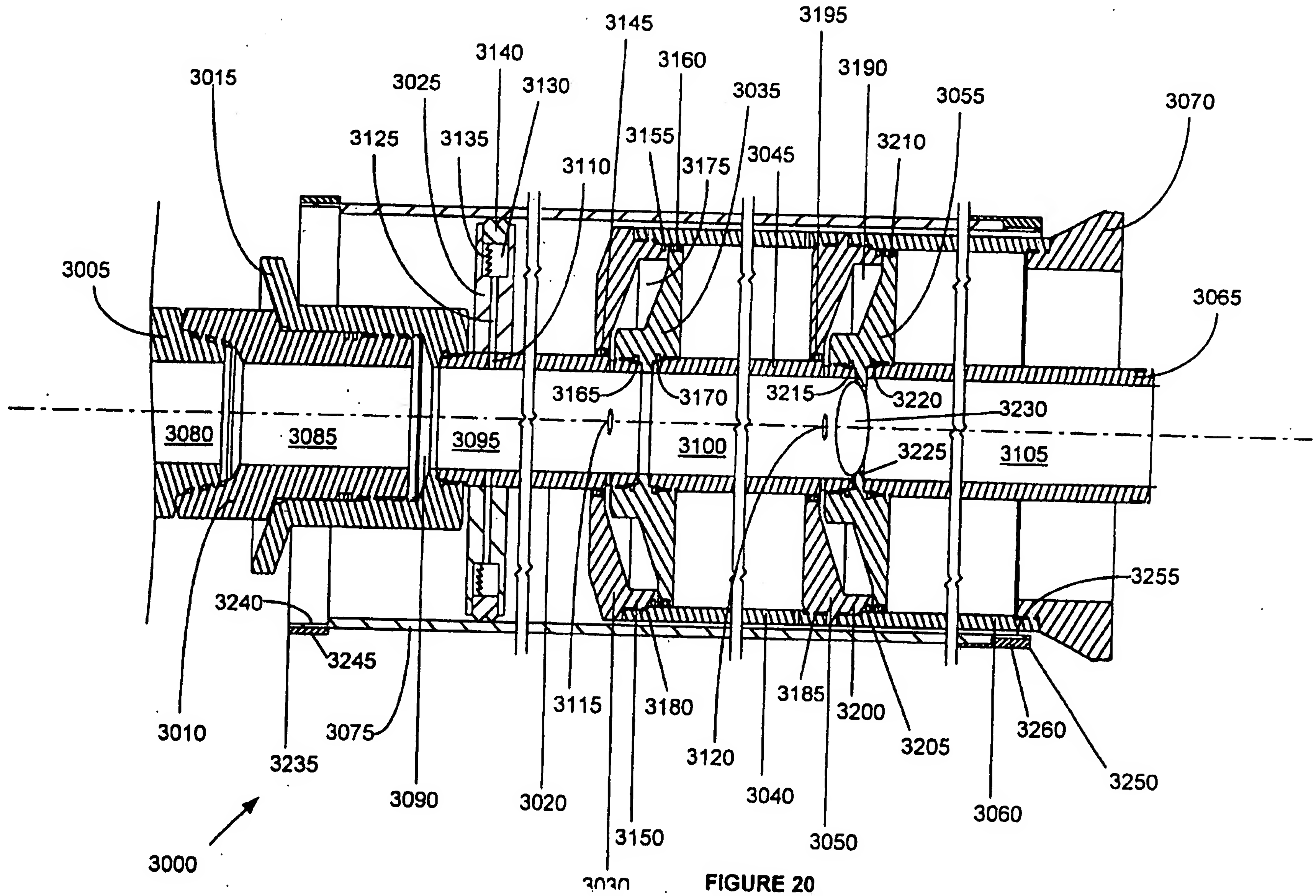
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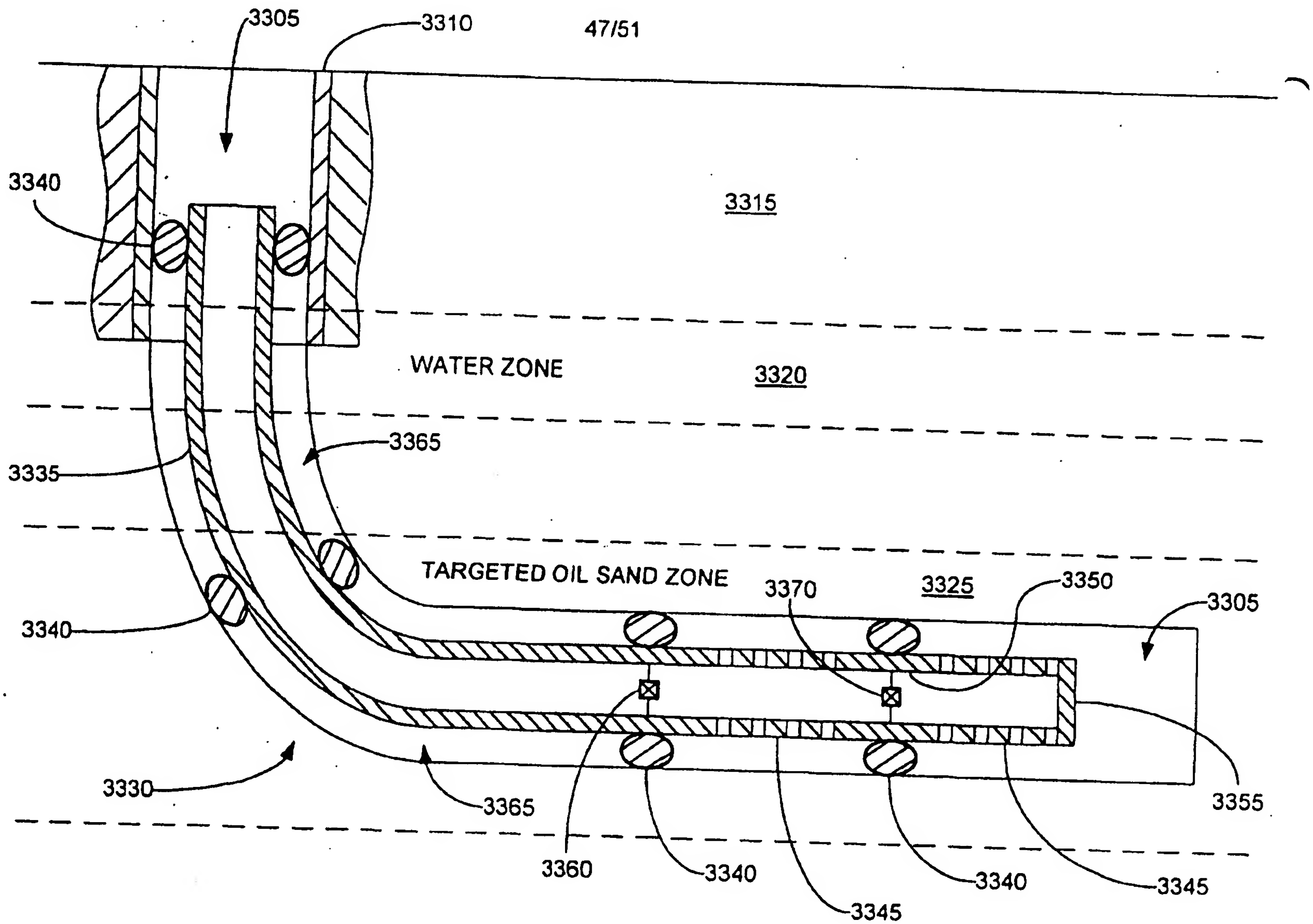
FIGURE 20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TARGETED OIL SAND ZONE
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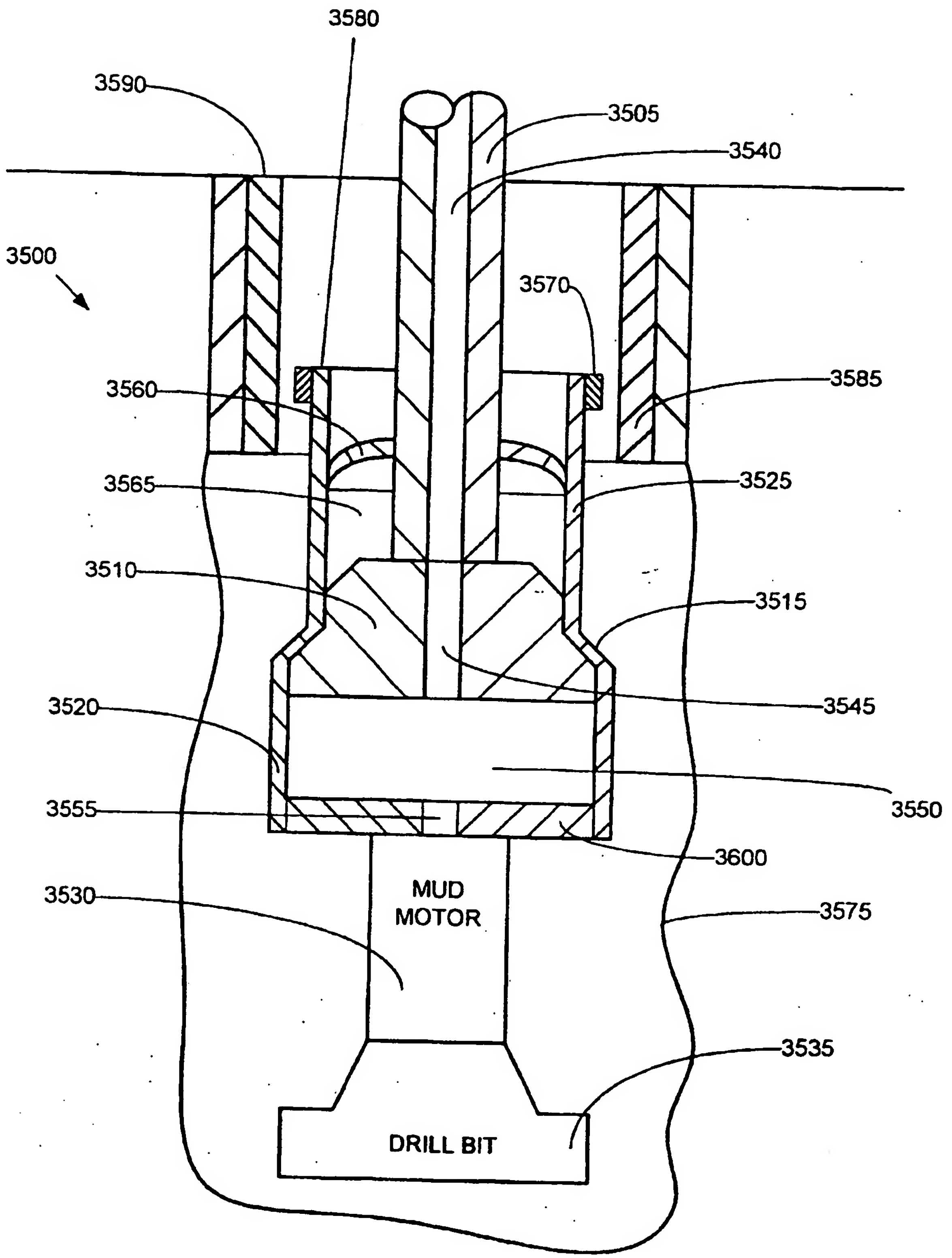
FIGURE 21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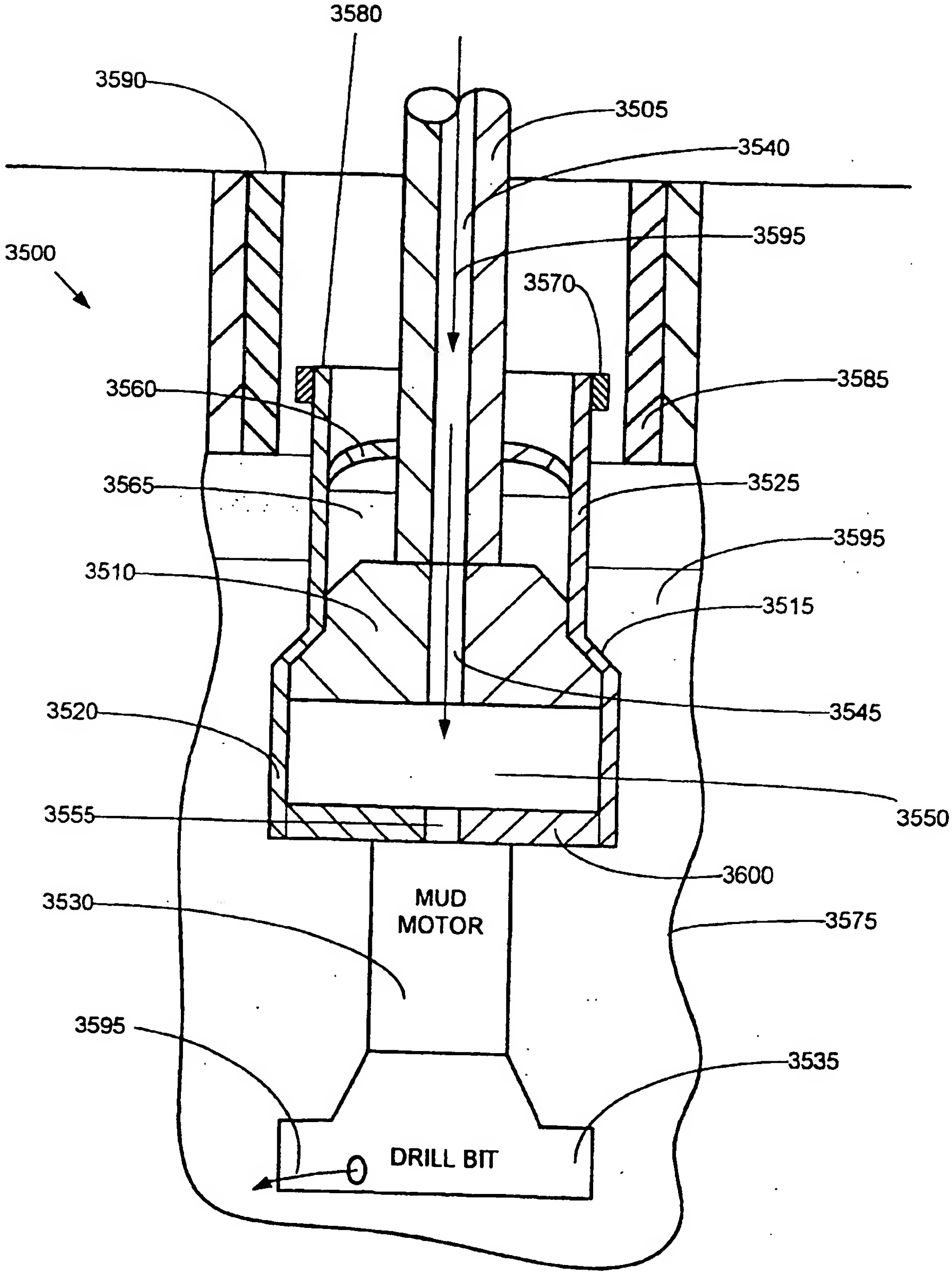
DRILL BIT

FIGURE 22A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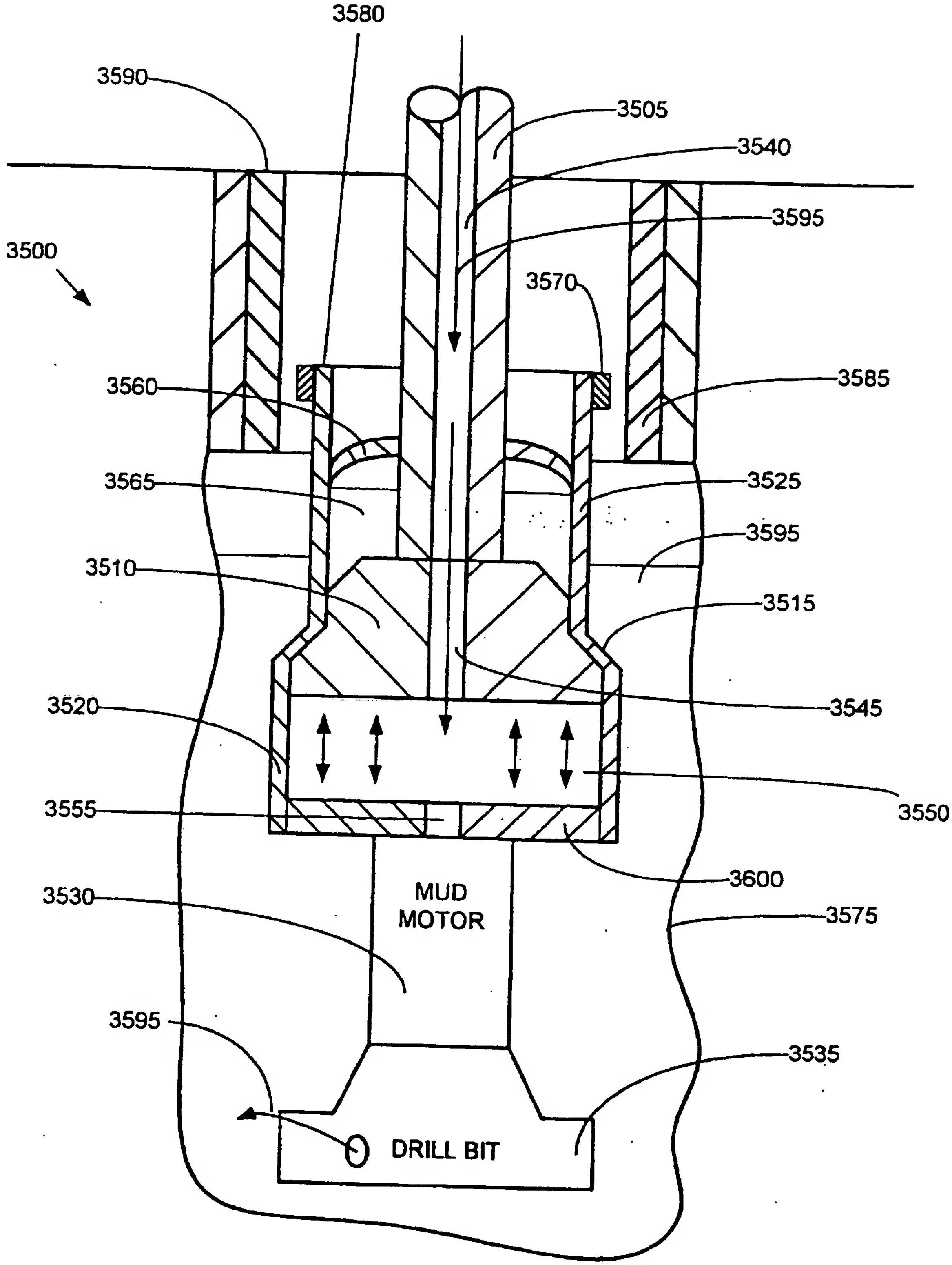
DRILL BIT

FIGURE 22B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MUD
MOTOR
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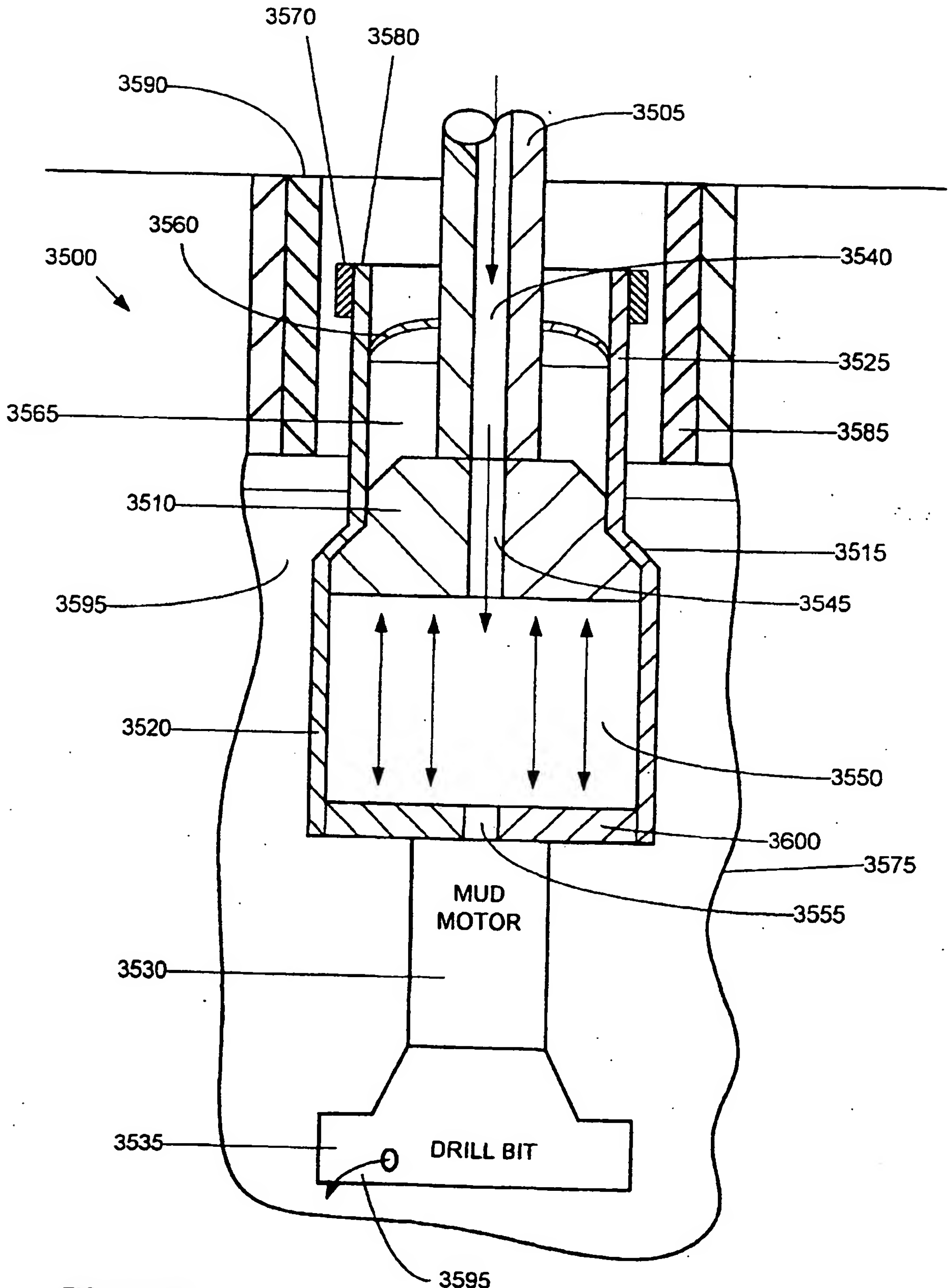
DRILL BIT

FIGURE 22C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MUD
MOTOR
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3530
3535
DRILL BIT
3595

FIGURE 22D

2385621

FORMING A WELLBORE CASING WHILE SIMULTANEOUSLY DRILLING A WELLBORE

Background of the Invention

This invention relates generally to wellbore casings, and in particular to wellbore casings that are formed using expandable tubing.

Conventionally, when a wellbore is created, a number of casings are installed in the borehole to prevent collapse of the borehole wall and to prevent undesired outflow of drilling fluid into the formation or inflow of fluid from the formation into the borehole. The borehole is drilled in intervals whereby a casing which is to be installed in a lower borehole interval is lowered through a previously installed casing of an upper borehole interval. As a consequence of this procedure the casing of the lower interval is of smaller diameter than the casing of the upper interval. Thus, the casings are in a nested arrangement with casing diameters decreasing in downward direction. Cement annuli are provided between the outer surfaces of the casings and the borehole wall to seal the casings from the borehole wall. As a consequence of this nested arrangement a relatively large borehole diameter is required at the upper part of the wellbore. Such a large borehole diameter involves increased costs due to heavy casing handling equipment, large drill bits and increased volumes of drilling fluid and drill cuttings. Moreover, increased drilling rig time is involved due to required cement pumping, cement hardening, required equipment changes due to large variations in hole diameters drilled in the course of the well, and the large volume of cuttings drilled and removed.

Conventionally, at the surface end of the wellbore, a wellhead is formed that typically includes a surface casing, a number of production and/or drilling spools, valving, and a Christmas tree. Typically the wellhead further includes a concentric arrangement of casings including a production casing and one or more intermediate casings. The casings are typically supported using load bearing slips positioned above the ground. The conventional design and construction of wellheads is expensive and complex.

Conventionally, a wellbore casing cannot be formed during the drilling of a wellbore. Typically, the wellbore is drilled and then a wellbore casing is formed in the newly drilled section of the wellbore. This delays the completion of a well.

The present invention is directed to overcoming one or more of the limitations of the existing procedures for forming wellbores and wellheads.

Summary of the Invention

According to the present invention, there is provided a method of forming an underground pipeline within an underground tunnel including at least a first tubular member and a second tubular member, the first tubular member having an inner diameter greater than an outer diameter of the second tubular member, comprising:

positioning the first tubular member within the tunnel;

positioning the second tubular member within the tunnel in an overlapping relationship with the first tubular member;

positioning a mandrel and a drilling assembly within an interior region of the second tubular member;

injecting a fluidic material within the mandrel, drilling assembly and the second tubular member;

extruding at least a portion of the second tubular member off of the mandrel into engagement with the first tubular member; and

drilling the tunnel.

Preferably, the pressurizing of the portion of the interior region of the second tubular member is provided at operating pressures ranging from about 500 to 9,000 psi (34.47 to 620.53 bar).

Preferably, the pressurizing of the portion of the interior region of the second tubular member is provided at reduced operating pressures during a latter portion of the extruding.

Preferably, the method further comprises sealing the interface between the first and second tubular members.

Preferably, the method further comprises supporting the extruded second tubular member using the interface with the first tubular member.

Preferably, the method further comprises lubricating the surface of the mandrel.

Preferably, the method further comprises absorbing shock.

Preferably, the method further comprises expanding the mandrel in a radial direction.

Preferably, the method further comprises fluidicly isolating the interior region of the second tubular member from an exterior region of the second tubular member.

Preferably, the interior region of the second tubular member is fluidicly isolated from the region exterior to the second tubular member by injecting one or more plugs into the interior of the second tubular member.

Preferably, the pressurizing of the portion of the interior region of the second tubular member is provided by injecting a fluidic material at operating pressures and flow rates ranging from about 500 to 9,000 psi and 40 to 3,000 gallons/minute (34.47 to 620.53 bar and 151.42 to 11356.24 litres/minute).

Preferably, the method further comprises injecting fluidic material beyond the mandrel.

Preferably, a region of the second tubular member beyond the mandrel is pressurized.

Preferably, the region of the second tubular member beyond the mandrel is pressurized to pressures ranging from about 500 to 9,000 psi (34.47 to 620.53 bar).

Preferably, the first tubular member comprises an existing section of the tunnel.

Preferably, the method further comprises sealing the interface between the first and second tubular members.

Preferably, the method further comprises supporting the extruded second tubular member using the first tubular member.

Preferably, the method further comprises testing the integrity of the seal in the interface between the first tubular member and the second tubular member.

Preferably, the method further comprises catching the mandrel upon the completion of the extruding.

Preferably, the method further comprises drilling out the mandrel.

Preferably, the method further comprises supporting the mandrel with coiled tubing.

Preferably, the method further comprises coupling the mandrel to a drillable shoe.

Brief Description of the Drawings

FIG. 1 is a fragmentary cross-sectional view illustrating the drilling of a new section of a well borehole.

FIG. 2 is a fragmentary cross-sectional view illustrating the placement of an apparatus for creating a casing within the new section of the well borehole.

FIG. 3 is a fragmentary cross-sectional view illustrating the injection of a first quantity of a fluidic material into the new section of the well borehole.

FIG. 3a is another fragmentary cross-sectional view illustrating the injection of a first quantity of a hardenable fluidic sealing material into the new section of the well borehole.

FIG. 4 is a fragmentary cross-sectional view illustrating the injection of a second quantity of a fluidic material into the new section of the well borehole.

FIG. 5 is a fragmentary cross-sectional view illustrating the drilling out of a portion of the cured hardenable fluidic sealing material from the new section of the well borehole.

FIG. 6 is a cross-sectional view of the overlapping joint between adjacent tubular members.

FIG. 7 is a fragmentary cross-sectional view of the apparatus for creating a casing within a well borehole.

FIG. 8 is a fragmentary cross-sectional illustration of the placement of an expanded tubular member within another tubular member.

FIG. 9 is a cross-sectional illustration of an apparatus for forming a casing including a drillable mandrel and shoe.

FIG. 9a is another cross-sectional illustration of the apparatus of FIG. 9.

FIG. 9b is another cross-sectional illustration of the apparatus of FIG. 9.

FIG. 9c is another cross-sectional illustration of the apparatus of FIG. 9.

FIG. 10a is a cross-sectional illustration of a wellbore including a pair of adjacent overlapping casings.

FIG. 10b is a cross-sectional illustration of an apparatus and method for creating a tie-back liner using an expandable tubular member.

FIG. 10c is a cross-sectional illustration of the pumping of a fluidic sealing material into the annular region between the tubular member and the existing casing.

FIG. 10d is a cross-sectional illustration of the pressurizing of the interior of the tubular member below the mandrel.

FIG. 10e is a cross-sectional illustration of the extrusion of the tubular member off of the mandrel.

FIG. 10f is a cross-sectional illustration of the tie-back liner before drilling out the shoe and packer.

FIG. 10g is a cross-sectional illustration of the completed tie-back liner created using an expandable tubular member.

FIG. 11a is a fragmentary cross-sectional view illustrating the drilling of a new section of a well borehole.

FIG. 11b is a fragmentary cross-sectional view illustrating the placement of an apparatus for hanging a tubular liner within the new section of the well borehole.

FIG. 11c is a fragmentary cross-sectional view illustrating the injection of a first quantity of a hardenable fluidic sealing material into the new section of the well borehole.

FIG. 11d is a fragmentary cross-sectional view illustrating the introduction of a wiper dart into the new section of the well borehole.

FIG. 11e is a fragmentary cross-sectional view illustrating the injection of a second quantity of a hardenable fluidic sealing material into the new section of the well borehole.

FIG. 11f is a fragmentary cross-sectional view illustrating the completion of the tubular liner.

FIG. 12 is a cross-sectional illustration of a wellhead system utilizing expandable tubular members.

FIG. 13 is a partial cross-sectional illustration of the wellhead system of FIG. 12.

FIG. 14a is an illustration of the formation of a mono-diameter wellbore casing.

FIG. 14b is another illustration of the formation of the mono-diameter wellbore casing.

FIG. 14c is another illustration of the formation of the mono-diameter wellbore casing.

FIG. 14d is another illustration of the formation of the mono-diameter wellbore casing.

FIG. 14e is another illustration of the formation of the mono-diameter wellbore casing.

FIG. 14f is another illustration of the formation of the mono-diameter wellbore casing.

FIG. 15 is an illustration of an apparatus for expanding a tubular member.

FIG. 15a is another illustration of the apparatus of FIG. 15.

FIG. 15b is another illustration of the apparatus of FIG. 15.

FIG. 16 is an illustration of an apparatus for forming a mono-diameter wellbore casing.

FIG. 17 is an illustration of an apparatus for expanding a tubular member.

FIG. 17a is another illustration of the apparatus of FIG. 16.

FIG. 17b is another illustration of the apparatus of FIG. 16.

FIG. 18 is an illustration of an apparatus for forming a mono-diameter wellbore casing.

FIG. 19 is an illustration of another apparatus for expanding a tubular member.

FIG. 19a is another illustration of the apparatus of FIG. 17.

FIG. 19b is another illustration of the apparatus of FIG. 17.

FIG. 20 is an illustration of an apparatus for forming a mono-diameter wellbore casing.

FIG. 21 is an illustration of the isolation of subterranean zones using expandable tubulars.

FIG. 22a is a fragmentary cross-sectional illustration of an apparatus for forming a wellbore casing while drilling a wellbore.

FIG. 22b is another fragmentary cross-sectional illustration of the apparatus of FIG. 22a.

FIG. 22c is another fragmentary cross-sectional illustration of the apparatus of FIG. 22a.

FIG. 22d is another fragmentary cross-sectional illustration of the apparatus of FIG. 22a.

Referring initially to Figs. 1-5, an apparatus and method for forming a wellbore casing within a subterranean formation will now be described. As illustrated in Fig. 1, a wellbore 100 is positioned in a subterranean formation 105. The wellbore 100 includes an existing cased section 110 having a tubular casing 115 and an annular outer layer of cement 120.

In order to extend the wellbore 100 into the subterranean formation 105, a drill string 125 is used in a well known manner to drill out material from the subterranean formation 105 to form a new section 130.

As illustrated in Fig. 2, an apparatus 200 for forming a wellbore casing in a subterranean formation is then positioned in the new section 130 of the wellbore 100. The apparatus 200 preferably includes an expandable mandrel or pig 205, a tubular member 210, a shoe 215, a lower cup seal 220, an upper cup seal 225, a fluid passage 230, a fluid passage 235, a fluid passage 240, seals 245, and a support member 250.

The expandable mandrel 205 is coupled to and supported by the support member 250. The expandable mandrel 205 is preferably adapted to controllably expand in a radial direction. The expandable mandrel 205 may comprise any number of conventional commercially available expandable mandrels modified in accordance with the teachings of the present disclosure. The expandable mandrel 205 comprises a hydraulic expansion tool as disclosed in U.S. Patent No. 5,348,095, the contents of which are incorporated herein by reference, modified in accordance with the teachings of the present disclosure.

The tubular member 210 is supported by the expandable mandrel 205. The tubular member 210 is expanded in the radial direction and extruded off of the expandable mandrel 205. The tubular member 210 may be fabricated from any number of conventional commercially available materials such as, for example, Oilfield Country Tubular Goods (OCTG), 13 chromium steel tubing/casing, or plastic

tubing/casing. The tubular member 210 is fabricated from OCTG in order to maximize strength after expansion. The inner and outer diameters of the tubular member 210 may range, for example, from approximately 0.75 to 47 inches and 1.05 to 48 inches, respectively. The inner and outer diameters of the tubular member 210 range from about 3 to 15.5 inches and 3.5 to 16 inches, respectively in order to optimally provide minimal telescoping effect in the most commonly drilled wellbore sizes. The tubular member 210 preferably comprises a solid member.

The end portion 260 of the tubular member 210 is slotted, perforated, or otherwise modified to catch or slow down the mandrel 205 when it completes the extrusion of tubular member 210. The length of the tubular member 210 is limited to minimize the possibility of buckling. For typical tubular member 210 materials, the length of the tubular member 210 is preferably limited to between about 40 to 20,000 feet in length.

The shoe 215 is coupled to the expandable mandrel 205 and the tubular member 210. The shoe 215 includes fluid passage 240. The shoe 215 may comprise any number of conventional commercially available shoes such as, for example, Super Seal II float shoe, Super Seal II Down-Jet float shoe or a guide shoe with a sealing sleeve for a latch down plug modified in accordance with the teachings of the present disclosure. The shoe 215 comprises an aluminum down-jet guide shoe with a sealing sleeve for a latch-down plug available from Halliburton Energy Services in Dallas, TX, modified in accordance with the teachings of the present disclosure, in order to optimally guide the tubular member 210 in the wellbore, optimally provide an adequate seal between the interior and exterior diameters of the overlapping joint between the tubular members, and to optimally allow the complete drill out of the shoe and plug after the completion of the cementing and expansion operations.

The shoe 215 includes one or more through and side outlet ports in fluidic communication with the fluid passage 240. In this manner, the shoe 215 optimally injects hardenable fluidic sealing material into the region outside the shoe 215 and tubular member 210. The shoe 215 includes the fluid passage 240 having an inlet geometry that can receive a dart and/or a ball sealing member. In this manner, the fluid

passage 240 can be optimally sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 230.

The lower cup seal 220 is coupled to and supported by the support member 250. The lower cup seal 220 prevents foreign materials from entering the interior region of the tubular member 210 adjacent to the expandable mandrel 205. The lower cup seal 220 may comprise any number of conventional commercially available cup seals such as, for example, TP cups, or Selective Injection Packer (SIP) cups modified in accordance with the teachings of the present disclosure. The lower cup seal 220 comprises a SIP cup seal, available from Halliburton Energy Services in Dallas, TX in order to optimally block foreign material and contain a body of lubricant.

The upper cup seal 225 is coupled to and supported by the support member 250. The upper cup seal 225 prevents foreign materials from entering the interior region of the tubular member 210. The upper cup seal 225 may comprise any number of conventional commercially available cup seals such as, for example, TP cups or SIP cups modified in accordance with the teachings of the present disclosure. The upper cup seal 225 comprises a SIP cup, available from Halliburton Energy Services in Dallas, TX in order to optimally block the entry of foreign materials and contain a body of lubricant.

The fluid passage 230 permits fluidic materials to be transported to and from the interior region of the tubular member 210 below the expandable mandrel 205. The fluid passage 230 is coupled to and positioned within the support member 250 and the expandable mandrel 205. The fluid passage 230 preferably extends from a position adjacent to the surface to the bottom of the expandable mandrel 205. The fluid passage 230 is preferably positioned along a centerline of the apparatus 200.

The fluid passage 230 is preferably selected, in the casing running mode of operation, to transport materials such as drilling mud or formation fluids at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to minimize drag on the tubular member being run and to minimize surge pressures exerted on the wellbore which could cause a loss of wellbore fluids and lead to hole collapse.

The fluid passage 235 permits fluidic materials to be released from the fluid passage 230. In this manner, during placement of the apparatus 200 within the new section 130 of the wellbore 100, fluidic materials 255 forced up the fluid passage 230 can be released into the wellbore 100 above the tubular member 210 thereby minimizing surge pressures on the wellbore section 130. The fluid passage 235 is coupled to and positioned within the support member 250. The fluid passage is further fluidicly coupled to the fluid passage 230.

The fluid passage 235 preferably includes a control valve for controllably opening and closing the fluid passage 235. The control valve is pressure activated in order to controllably minimize surge pressures. The fluid passage 235 is preferably positioned substantially orthogonal to the centerline of the apparatus 200.

The fluid passage 235 is preferably selected to convey fluidic materials at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to reduce the drag on the apparatus 200 during insertion into the new section 130 of the wellbore 100 and to minimize surge pressures on the new wellbore section 130.

The fluid passage 240 permits fluidic materials to be transported to and from the region exterior to the tubular member 210 and shoe 215. The fluid passage 240 is coupled to and positioned within the shoe 215 in fluidic communication with the interior region of the tubular member 210 below the expandable mandrel 205. The fluid passage 240 preferably has a cross-sectional shape that permits a plug, or other similar device, to be placed in fluid passage 240 to thereby block further passage of fluidic materials. In this manner, the interior region of the tubular member 210 below the expandable mandrel 205 can be fluidicly isolated from the region exterior to the tubular member 210. This permits the interior region of the tubular member 210 below the expandable mandrel 205 to be pressurized. The fluid passage 240 is preferably positioned substantially along the centerline of the apparatus 200.

The fluid passage 240 is preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally fill the annular region between the tubular member 210 and the new section 130 of the wellbore 100 with fluidic materials. The fluid passage 240 includes an inlet geometry that can receive a dart

and/or a ball sealing member. In this manner, the fluid passage 240 can be sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 230.

The seals 245 are coupled to and supported by an end portion 260 of the tubular member 210. The seals 245 are further positioned on an outer surface 265 of the end portion 260 of the tubular member 210. The seals 245 permit the overlapping joint between the end portion 270 of the casing 115 and the portion 260 of the tubular member 210 to be fluidicly sealed. The seals 245 may comprise any number of conventional commercially available seals such as, for example, lead, rubber, Teflon, or epoxy seals modified in accordance with the teachings of the present disclosure. The seals 245 are molded from Stratalock epoxy available from Halliburton Energy Services in Dallas, TX in order to optimally provide a load bearing interference fit between the end 260 of the tubular member 210 and the end 270 of the existing casing 115.

The seals 245 are selected to optimally provide a sufficient frictional force to support the expanded tubular member 210 from the existing casing 115. The frictional force optimally provided by the seals 245 ranges from about 1,000 to 1,000,000 lbf in order to optimally support the expanded tubular member 210.

The support member 250 is coupled to the expandable mandrel 205, tubular member 210, shoe 215, and seals 220 and 225. The support member 250 preferably comprises an annular member having sufficient strength to carry the apparatus 200 into the new section 130 of the wellbore 100. The support member 250 further includes one or more conventional centralizers (not illustrated) to help stabilize the apparatus 200. The support member 250 comprises coiled tubing.

A quantity of lubricant 275 is provided in the annular region above the expandable mandrel 205 within the interior of the tubular member 210. In this manner, the extrusion of the tubular member 210 off of the expandable mandrel 205 is facilitated. The lubricant 275 may comprise any number of conventional commercially available lubricants such as, for example, Lubriplate, chlorine based lubricants, oil based lubricants or Climax 1500 Antisieze (3100). The lubricant 275 comprises Climax 1500 Antisieze (3100) available from Climax Lubricants and Equipment Co. in

Houston, TX in order to optimally provide optimum lubrication to facilitate the expansion process.

The support member 250 is thoroughly cleaned prior to assembly to the remaining portions of the apparatus 200. In this manner, the introduction of foreign material into the apparatus 200 is minimized. This minimizes the possibility of foreign material clogging the various flow passages and valves of the apparatus 200.

Before or after positioning the apparatus 200 within the new section 130 of the wellbore 100, a couple of wellbore volumes are circulated in order to ensure that no foreign materials are located within the wellbore 100 that might clog up the various flow passages and valves of the apparatus 200 and to ensure that no foreign material interferes with the expansion process.

As illustrated in Fig. 3, the fluid passage 235 is then closed and a hardenable fluidic sealing material 305 is then pumped from a surface location into the fluid passage 230. The material 305 then passes from the fluid passage 230 into the interior region 310 of the tubular member 210 below the expandable mandrel 205. The material 305 then passes from the interior region 310 into the fluid passage 240. The material 305 then exits the apparatus 200 and fills the annular region 315 between the exterior of the tubular member 210 and the interior wall of the new section 130 of the wellbore 100. Continued pumping of the material 305 causes the material 305 to fill up at least a portion of the annular region 315.

The material 305 is preferably pumped into the annular region 315 at pressures and flow rates ranging, for example, from about 0 to 5000 psi and 0 to 1,500 gallons/min, respectively. The optimum flow rate and operating pressures vary as a function of the casing and wellbore sizes, wellbore section length, available pumping equipment, and fluid properties of the fluidic material being pumped. The optimum flow rate and operating pressure are preferably determined using conventional empirical methods.

The hardenable fluidic sealing material 305 may comprise any number of conventional commercially available hardenable fluidic sealing materials such as, for example, slag mix, cement or epoxy. The hardenable fluidic sealing material 305 comprises a blended cement prepared specifically for the particular well section being

drilled from Halliburton Energy Services in Dallas, TX in order to provide optimal support for tubular member 210 while also maintaining optimum flow characteristics so as to minimize difficulties during the displacement of cement in the annular region 315. The optimum blend of the blended cement is preferably determined using conventional empirical methods.

The annular region 315 preferably is filled with the material 305 in sufficient quantities to ensure that, upon radial expansion of the tubular member 210, the annular region 315 of the new section 130 of the wellbore 100 will be filled with material 305.

As illustrated in Fig. 3a, the wall thickness and/or the outer diameter of the tubular member 210 is reduced in the region adjacent to the mandrel 205 in order optimally permit placement of the apparatus 200 in positions in the wellbore with tight clearances. Furthermore, in this manner, the initiation of the radial expansion of the tubular member 210 during the extrusion process is optimally facilitated.

As illustrated in Fig. 4, once the annular region 315 has been adequately filled with material 305, a plug 405, or other similar device, is introduced into the fluid passage 240 thereby fluidicly isolating the interior region 310 from the annular region 315. A non-hardenable fluidic material 306 is then pumped into the interior region 310 causing the interior region to pressurize. In this manner, the interior of the expanded tubular member 210 will not contain significant amounts of cured material 305. This reduces and simplifies the cost of the entire process. Alternatively, the material 305 may be used during this phase of the process.

Once the interior region 310 becomes sufficiently pressurized, the tubular member 210 is extruded off of the expandable mandrel 205. During the extrusion process, the expandable mandrel 205 may be raised out of the expanded portion of the tubular member 210. During the extrusion process, the mandrel 205 is raised at approximately the same rate as the tubular member 210 is expanded in order to keep the tubular member 210 stationary relative to the new wellbore section 130. The extrusion process is commenced with the tubular member 210 positioned above the bottom of the new wellbore section 130, keeping the mandrel 205 stationary, and allowing the tubular member 210 to extrude off of the mandrel 205 and fall down the new wellbore section 130 under the force of gravity.

The plug 405 is preferably placed into the fluid passage 240 by introducing the plug 405 into the fluid passage 230 at a surface location in a conventional manner. The plug 405 preferably acts to fluidicly isolate the hardenable fluidic sealing material 305 from the non hardenable fluidic material 306.

The plug 405 may comprise any number of conventional commercially available devices from plugging a fluid passage such as, for example, Multiple Stage Cementer (MSC) latch-down plug, Omega latch-down plug or three-wiper latch-down plug modified in accordance with the teachings of the present disclosure. The plug 405 comprises a MSC latch-down plug available from Halliburton Energy Services in Dallas, TX.

After placement of the plug 405 in the fluid passage 240, a non hardenable fluidic material 306 is preferably pumped into the interior region 310 at pressures and flow rates ranging, for example, from approximately 400 to 10,000 psi and 30 to 4,000 gallons/min. In this manner, the amount of hardenable fluidic sealing material within the interior 310 of the tubular member 210 is minimized. After placement of the plug 405 in the fluid passage 240, the non hardenable material 306 is preferably pumped into the interior region 310 at pressures and flow rates ranging from approximately 500 to 9,000 psi and 40 to 3,000 gallons/min in order to maximize the extrusion speed.

The apparatus 200 is adapted to minimize tensile, burst, and friction effects upon the tubular member 210 during the expansion process. These effects will depend upon the geometry of the expansion mandrel 205, the material composition of the tubular member 210 and expansion mandrel 205, the inner diameter of the tubular member 210, the wall thickness of the tubular member 210, the type of lubricant, and the yield strength of the tubular member 210. In general, the thicker the wall thickness, the smaller the inner diameter, and the greater the yield strength of the tubular member 210, then the greater the operating pressures required to extrude the tubular member 210 off of the mandrel 205.

For typical tubular members 210, the extrusion of the tubular member 210 off of the expandable mandrel will begin when the pressure of the interior region 310 reaches, for example, approximately 500 to 9,000 psi.

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